FORM 10-K

Armstrong Energy, Inc. - N/A

Filed: March 31, 2017 (period: December 31, 2016)

Annual report with a comprehensive overview of the company

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2016

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission File Number: 333-191182

Armstrong Energy, Inc.
(Exact name of registrant as specified in its charter)

Delaware	**20-8015664**
(State or other jurisdiction of incorporation or organization)	**(IRS Employer Identification No.)**
7733 Forsyth Boulevard, Suite 1625 **St. Louis, Missouri**	**63105**
(Address of principal executive offices)	**(Zip code)**

(314) 721 – 8202
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act: None

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. ☐ Yes ☒ No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. ☐ Yes ☒ No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☒ Yes ☐ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). ☒ Yes ☐ No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☐	Accelerated filer	☐
Non-accelerated filer	☒ (Do not check if a smaller reporting company)	Smaller reporting company	☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). ☐ Yes ☒ No

As of June 30, 2016, there was no established public market for the registrant's voting and non-voting common stock and therefore the aggregate market value of the voting and non-voting common equity held by non-affiliates is not determinable.

As of March 30, 2017, there were 21,883,224 shares of Armstrong Energy, Inc.'s common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

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CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

Various statements contained in this annual report, including those that express a belief, expectation or intention, as well as those that are not statements of historical fact, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, (the Securities Act) and Section 21E of the Securities Exchange Act of 1934, as amended (the Exchange Act). These forward-looking statements may include projections and estimates concerning the timing and success of specific projects and our future production, revenues, income and capital spending. Our forward-looking statements are generally accompanied by words such as “estimate,” “project,” “predict,” “believe,” “expect,” “anticipate,” “potential,” “plan,” “goal” or other words that convey the uncertainty of future events or outcomes. The forward-looking statements in this annual report speak only as of the date of this annual report; we disclaim any obligation to update these statements unless required by law, and we caution you not to rely on them unduly. We have based these forward-looking statements on our current expectations and assumptions about future events. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. These and other important factors may cause our actual results, performance or achievements to differ materially from any future results, performance or achievements expressed or implied by these forward-looking statements. These risks, contingencies and uncertainties include, but are not limited to, the following:

- our ability to continue as a going concern within one year beyond the filing of this Annual Report on Form 10-K;
- liquidity constraints and our ability to service our outstanding indebtedness;
- our ability to comply with the restrictions imposed by the indenture governing our notes and other financing arrangements;
- market demand for coal and electricity;
- geologic conditions, weather and other inherent risks of coal mining that are beyond our control;
- competition within our industry and with producers of competing energy sources;
- excess production and production capacity;
- our ability to acquire or develop coal reserves in an economically feasible manner;
- inaccuracies in our estimates of our coal reserves;
- availability and price of mining and other industrial supplies, including steel-based supplies, diesel fuel, rubber tires and explosives;
- the continued weakness in global economic conditions or in any industry in which our customers operate, or sustained uncertainty in financial markets, which may cause conditions we cannot predict;
- coal users switching to other fuels in order to comply with various environmental standards related to coal combustion;
- volatility in the capital and credit markets;
- availability of skilled employees and other workforce factors;
- our ability to collect payments from our customers;
- defects in title or the loss of a leasehold interest;
- railroad, barge, truck and other transportation performance and costs;
- our ability to secure new coal supply arrangements or to renew existing coal supply arrangements;
- the deferral of contracted shipments of coal by our customers;
- our ability to obtain or renew surety bonds on acceptable terms;
- our ability to obtain and renew various permits, including permits authorizing the disposition of certain mining waste;

- existing and future legislation and regulations affecting both our coal mining operations and our customers' coal usage, governmental policies and taxes, including those aimed at reducing emissions of elements such as mercury, sulfur dioxide, nitrogen oxides, or toxic gases, such as hydrogen chloride, particulate matter or greenhouse gases;
- the accuracy of our estimates of reclamation and other mine closure obligations;
- our ability to attract and retain key management personnel;
- efforts to organize our workforce for representation under a collective bargaining agreement; and
- other factors, including those discussed in Item 1A – "Risk Factors" of this Annual Report on Form 10-K.

PART I

Item 1. Business

Overview

Our History

Armstrong Energy, Inc. (together with its subsidiaries, we, Armstrong Energy, or the Company) is a producer of low chlorine, high sulfur thermal coal from the Illinois Basin, with both surface and underground mines. We market our coal primarily to proximate and investment grade electric utility companies as fuel for their steam-powered generators. Based on 2016 production, we are the sixth largest producer in the Illinois Basin and the second largest in Western Kentucky.

We were formed in 2006 to acquire and develop a large coal reserve holding. Between 2006 and 2011, we completed six transactions, either directly or through our affiliate, Thoroughbred Resources, L.P. (Thoroughbred), to acquire mineral reserves and land from Peabody Energy, Inc. (Peabody). We commenced production in the second quarter of 2008 and currently operate five mines, including three surface and two underground. Since 2008, we have continued to acquire additional mineral reserves, which are strategic to our operating plans and currently control approximately 567 million tons of proven and probable coal reserves. We also own and operate three coal processing plants, which support our mining operations. From our reserves, we mine coal from multiple seams that, in combination with our coal processing facilities, enhance our ability to meet customer requirements for blends of coal with different characteristics. The locations of our coal reserves and operations, adjacent to the Green River, together with our river dock coal handling and rail loadout facilities, allow us to optimize our coal blending and handling, and provide our customers with rail, barge and truck transportation options.

We are majority-owned by investment funds managed by Yorktown Partners LLC (Yorktown). Yorktown was formed in 1991 and has approximately $3.0 billion in assets under management. Yorktown invests exclusively in the energy industry with an emphasis on North American oil and gas production, coal mining and midstream businesses. Yorktown's investors include university endowments, foundations, families, insurance companies and other institutional investors. As a result of its significant ownership of Armstrong Energy, Yorktown has, and can be expected to have, a significant influence in our operations, in the outcome of stockholder voting concerning the election of directors, the adoption or amendment of provisions in our charter and bylaws, the approval of mergers, and other significant corporate matters.

We operate in one reporting segment. For information regarding our revenue, long-lived assets, and total assets, please see Item 7 – "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Item 8 – "Financial Statements and Supplementary Data."

Liquidity and Going Concern

Our consolidated financial statements have been prepared assuming we will continue as a going concern, which contemplates continuity of operations, realization of assets and the satisfaction of liabilities in the normal course of business. As such, the accompanying consolidated financial statements do not include any adjustments relating to the recoverability and classification of assets and their carrying amounts, or the amount and classification of liabilities that may result should we be unable to continue as a going concern.

Although we are taking steps to minimize our capital expenditures, reduce costs and maximize cash flows from operations, our liquidity outlook has continued to deteriorate since the third quarter of 2016. Continued depressed coal market fundamentals are expected to negatively impact our operating results and lead to significantly lower levels of cash flow from operating activities in the near-term. As a result of these and other factors, there is substantial doubt about our ability to continue as a going concern. See Note 3, "Liquidity and Going Concern," to our audited consolidated financial statements, included in Item 8 - "Financial Statements and Supplementary Data," of this Annual Report on Form 10-K.

Our Relationship with Thoroughbred Resources, L.P.

Thoroughbred was formed in 2008 to engage in the business of management and leasing of coal properties and collection of royalties in the Western Kentucky region of the Illinois Basin. Prior to September 1, 2016, our wholly-owned subsidiary, Elk Creek GP, LLC (ECGP), was the sole general partner of, and had an approximate 0.2% ownership in, Thoroughbred. The various limited partners of Thoroughbred are related parties, as the majority of the limited partnership interests (common units) of Thoroughbred are owned by Yorktown. Effective September 1, 2016, Yorktown exercised its right under the Second Amended and Restated Agreement of Limited Partnership of Thoroughbred Resources, LP to remove ECGP as the general partner of Thoroughbred. We continue to maintain a 0.9% interest in Thoroughbred through our subsidiary, Armstrong Energy

Holdings, Inc. We account for our remaining investment in Thoroughbred under the cost method, and we do not consolidate the financial results of Thoroughbred.

Beginning in 2011, Thoroughbred acquired, through multiple transactions, an undivided interest in certain land and mineral reserves of Armstrong Energy in Muhlenberg and Ohio Counties, Kentucky. As of December 31, 2016, Thoroughbred owns a 79.19% undivided interest in approximately 179 million tons of our mineral reserves. In conjunction with the aforementioned acquisitions, Armstrong Energy entered into lease agreements with Thoroughbred pursuant to which Thoroughbred granted Armstrong Energy leases to its undivided interest in the mining properties acquired and licenses to mine coal on those properties in exchange for a production royalty.

In addition, we have also leased approximately 250 million tons of mineral reserves wholly-owned by Thoroughbred in exchange for a production royalty. See Item 13 - “Certain Relationships and Related-Party Transactions, and Director Independence.”

Starting in December 2016, we received the first of multiple communications from Thoroughbred Holdings GP, LLC (Thoroughbred Holdings), the general partner of Thoroughbred, and their legal counsel alleging claims associated with various transactions between the parties. Thoroughbred Holdings claimed the third-party valuations prepared annually in order to determine the percentage interest in certain jointly-owned land and mineral reserves (the Jointly-Owned Property) to be transferred from us to Thoroughbred pursuant to the First Amended and Restated Royalty Deferment and Option Agreement (the Royalty Agreement) were inaccurate in 2016 and prior, which resulted in the underpayment of production royalties to Thoroughbred. In addition, Thoroughbred Holdings has taken exception to our calculation of the amount of deferred royalties for the year ended December 31, 2016, the amount of certain offsets from these deferred royalties by amounts due from Thoroughbred to us pursuant to an Administrative Services Agreement, and the offset of certain production royalties that we have overpaid to Thoroughbred on properties other than the Jointly-Owned Property.

Following a series of negotiations, Armstrong and certain of its affiliates, and Thoroughbred Holdings and certain of its affiliates, entered into a settlement agreement effective March 29, 2017 (the Settlement Agreement) to resolve all of these claims and to avoid the uncertainties of a potential lengthy arbitration. Refer to Note 13, “Related-Party Transactions,” to our audited consolidated financial statements, included in Item 8 - “Financial Statements and Supplementary Data,” of this Annual Report on Form 10-K for further information regarding the settlement agreement.

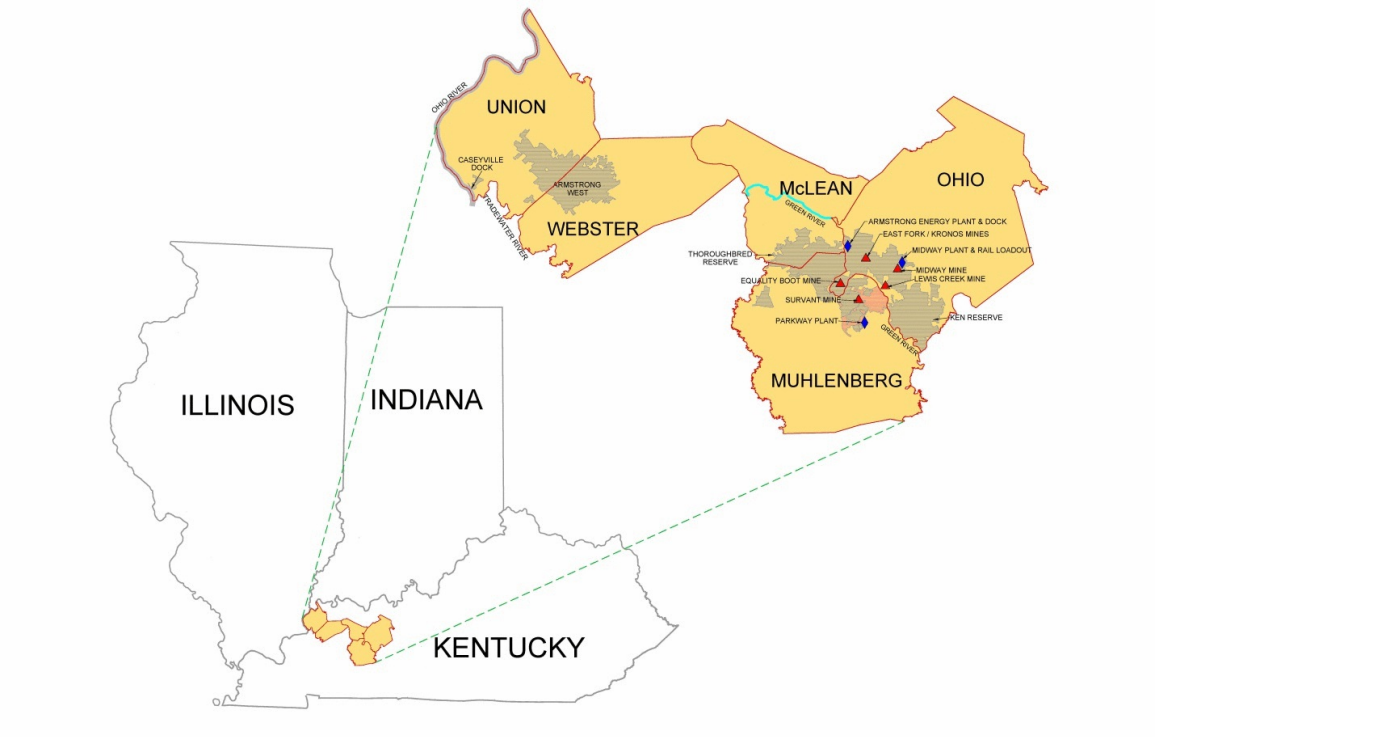
Our Mining Operations

We currently operate five active mines, all of which are located in the Illinois Basin coal region in western Kentucky. Our active operations are comprised of three surface mines and two underground mines, and we have three preparation plants serving these operations. In 2016, approximately 44% of the coal that we produced came from our surface mining operations.

Our current operating mines are all located in Muhlenberg and Ohio Counties, Kentucky. The Western Kentucky Parkway crosses our properties from Southwest to Northeast, and the Green River separates our properties in Ohio and Muhlenberg Counties. Our barge loading facility on the Green River is located near the town of Kirtley, Kentucky. In addition, we have a network of off-highway truck haul roads, which connect the majority of our active mines and provide access to our barge loading and rail loadout facilities. In general, we have developed our mines and preparation plants at strategic locations in close proximity to rail or barge shipping facilities.

We control approximately 567 million tons of proven and probable coal reserves in Ohio, Muhlenberg, McLean, Webster, and Union counties in Western Kentucky, of which we lease or sublease approximately 133 million tons from various unaffiliated landowners.

The following map shows the locations of our mining operations and coal reserves:



Equality Boot Mine. The Equality Boot mine is a surface mining operation located eight miles southwest of Centertown, Kentucky, which commenced operations in September 2010. The Equality Boot mine extracts thermal coal from the West Kentucky #14, #13, #12 and #11 seams and produced approximately 1.6 million tons of coal in 2016. The Equality Boot mine currently uses one dragline equipped with a 45 yard bucket and a spread of surface equipment, including power shovels, excavators, loaders and haul trucks, to remove overburden and interburden and construct the dragline bench. The Equality Boot mine had approximately 11.6 million tons of proven and probable reserves as of December 31, 2016. Coal from the Equality Boot mine is primarily transported less than one mile by truck to a 4,400 foot overland conveyor system, which is used to transport the coal to the 2,500 tons per hour barge loadout facility located on the Green River. The coal is then loaded onto barges and transported approximately five miles to the Armstrong Dock Preparation Plant where it is unloaded, processed, reloaded onto barges and then shipped to customers.

Lewis Creek Mine. The Lewis Creek mine is a surface mine located approximately five miles south of Centertown, Kentucky, and approximately 3.5 miles from the Midway Preparation Plant. Production commenced in June 2011 at the Lewis Creek mine, and thermal coal is being mined from the West Kentucky seams #13A and #13. Lewis Creek produced approximately 0.9 million tons of clean coal in 2016. A dragline equipped with a 20 yard bucket is used in conjunction with mobile mining equipment to remove overburden and construct the dragline bench at the Lewis Creek mine. As of December 31, 2016, there were approximately 7.2 million tons of proven and probable reserves at the Lewis Creek surface mine. Coal mined at the Lewis Creek mine is primarily transported by truck to the Midway Preparation Plant for processing and subsequent delivery to our customers.

Kronos Underground Mine. The Kronos underground mine, which commenced operations in September 2011, is located approximately three miles southwest of Centertown, Kentucky. It extracts thermal coal from the West Kentucky #9 seam. The Kronos underground mine produced approximately 2.1 million clean tons of coal in 2016. The mine utilizes four continuous miner super sections, and there were approximately 30.9 million tons of proven and probable reserves at the Kronos underground mine as of December 31, 2016. Coal mined at the Kronos underground mine is transported by truck to the Midway Preparation Plant and by conveyor to the Armstrong Dock Preparation Plant for processing and delivery to our customers.

Survant Underground Mine. The Survant underground mine, which is located at our Parkway complex, came out of development in August 2015. The Survant underground mine extracts coal from the West Kentucky #8 seam and produced

approximately 0.7 million clean tons of coal in 2016 through the operation of primarily one continuous miner super section. As of December 31, 2016, there were approximately 55.4 million tons of proven and probably reserves at the Survant underground mine. Coal mined from the Survant underground mine is primarily processed at the Parkway Preparation Plant prior to shipment to the ultimate customer.

Midway Mine. The Midway mine is a surface mine located two miles southeast of Centertown, Kentucky in Ohio County and is west of and adjacent to the Midway Preparation Plant. The Midway mine commenced production in April 2008 and extracted thermal coal from the West Kentucky #13a, #13, and #11 seams utilizing one dragline (45 yard bucket) and a spread of surface mining equipment, including power shovels, excavators, loaders and haul trucks. Coal from the Midway mine was primarily transported less than one mile by truck to the Midway Preparation Plant for processing, where it is then shipped to customers via truck, rail or barge. On December 31, 2015, production at the Midway mine was temporarily idled due to declining market conditions. Our reserve studies indicate the Midway mine has approximately 14.2 million tons of proven and probable reserves as of December 31, 2016.

Parkway Underground Mine. The Parkway underground mine was located northeast of Central City, Kentucky in Muhlenberg County. The Parkway underground mine extracted thermal coal primarily from the West Kentucky #9 seam and accessed that seam from an older surface mining pit that was abandoned prior to our acquisition of the Parkway underground mine. The Parkway underground mine produced approximately 0.5 million tons of clean coal in 2016. In October 2016, production ceased at the Parkway underground mine as the economically recoverable reserves had been depleted.

Future Mines. We continue to evaluate our mine plans and expect to open additional mines in order to replace existing mines as the reserves are depleted.

Our Coal Preparation Facilities

The majority of coal from each of our mining operations is processed at a coal preparation plant located near the mine or connected to the mine by an overland conveyor system. Currently, we have three preparation plants, Midway, Parkway and Armstrong Dock. These coal preparation plants allow us to process the coal we extract from our mines to ensure a consistent quality and to enhance its suitability for particular end-users. In 2016, our preparation plants processed approximately 96% of the raw coal we produced. In addition, depending on coal quality and customer requirements, we may blend coal mined from different locations in order to achieve a more suitable product. At the current time, our preparation plants do not process coal from other companies, and we do not have any present intention to do so.

The following chart provides information regarding our preparation plants:

	Midway	Parkway	Armstrong Dock
Location:	Centertown, Kentucky	Central City, Kentucky	Centertown, Kentucky
Inception:	July 2008	April 2009	March 2010
Mines Serviced:	Midway, Lewis Creek, Kronos Underground	Survant Underground	Equality Boot, Kronos Underground
Current Capacity (Tons Per Hour):	1,200	400	1,200
Average Capacity Utilization:	66.9%	69.7%	98.4%
Loadout Tons Per Hour:	2,500 (Rail)	—	2,500 (Barge)
Transportation:	Rail, Truck	Truck	Barge

The treatments we employ at our preparation plants depend on the size of the raw coal. For coarse material, the separation process relies on the difference in the density between coal and waste rock where, for the very fine fractions, the separation process relies on the difference in surface chemical properties between coal and the waste minerals. To remove impurities, we crush raw coal and classify it into various sizes. For the largest size fractions, we use dense media vessel separation techniques in which we float coal in a tank containing a liquid of a pre-determined specific gravity. Since coal is lighter than its impurities, it floats, and we can separate it from rock and shale. We treat intermediate sized particles with dense medium cyclones, in which a liquid is spun at high speeds to separate coal from rock. Fine coal is treated in spirals, in which the differences in density between coal and rock allow them, when suspended in water, to be separated. Ultra fine coal is recovered in column flotation cells utilizing the differences in surface chemistry between coal and rock. By injecting stable air bubbles through a suspension of ultra fine coal and rock, the coal particles adhere to the bubbles and rise to the surface of the column where they are removed. To minimize the moisture content in coal, we process most coal sizes through centrifuges. A

centrifuge spins coal very quickly, causing water accompanying the coal to separate. Coarse refuse from our preparation plants is back-hauled and disposed of in our mining pits or other locations in accordance with applicable regulations and permits.

Customers

Our primary customers are electric utilities. We may also sell coal to industrial companies, brokers and other coal producers. For the year ended December 31, 2016, approximately 99% of our coal revenues related to sales to electric utilities. The majority of our electric utility customers purchase coal for terms of one to four years, but we also supply coal on a spot basis for some of our customers.

In 2016, we sold coal to six domestic customers with operations located in numerous states. The majority of those customers operate power plants in the Midwestern and Southern regions of the United States. For the year ended December 31, 2016, we derived approximately 45% and 40% of our total coal revenues from sales to our two largest customers, Louisville Gas & Electric Company and the Tennessee Valley Authority, respectively.

Multi-year Coal Supply Agreements

As is customary in the coal industry, we enter into multi-year coal supply agreements with many of our customers. Multi-year coal supply agreements usually have specific volume and pricing arrangements for each year of the agreement. These agreements allow customers to secure a supply for their future needs and provide us with greater predictability of sales volume and sales prices. In 2016, we sold approximately 99% of our coal under multi-year coal supply agreements. The majority of our multi-year coal supply agreements include a fixed price for the term of the agreement or a pre-determined escalation in price for each year. Some of our multi-year coal supply agreements may include a variable pricing system. At December 31, 2016, we had multi-year coal supply agreements with remaining terms ranging from one to four years, and we are contractually committed to sell 5.3 million tons of coal in 2017.

We typically enter into multi-year coal supply agreements through a “request-for-proposal” process and after competitive bidding and negotiations. Therefore, the terms of these agreements vary by customer. Our multi-year coal supply agreements typically contain provisions to adjust the base price due to new laws and regulations that affect our costs. Additionally, some of our agreements contain provisions that allow for the recovery of costs affected by modifications or changes in the interpretations or application of any applicable statute by local, state or federal government authorities.

The price of coal sold under certain of our agreements is subject to fluctuation. For example, some of our agreements include index provisions that change the price based on changes in market-based indices and or changes in economic indices. Other agreements contain price reopener provisions that may allow a party to renegotiate pricing at a set time. Price reopener provisions may automatically set a new price based on then-current market prices or require us to negotiate a new price. In a limited number of agreements, if the parties do not agree on a new price, either party has an option to terminate the agreement. In addition, certain of our agreements contain clauses that may allow customers to terminate the agreement in the event of certain changes in environmental laws and regulations that affect their operations.

The coal supply agreements establish the quality and volume of coal to be sold. Most of our agreements fix annual pricing and volume obligations, though, in certain instances, the volume obligations may change depending on the customer’s needs. Most of our coal supply agreements contain provisions requiring us to deliver coal within certain ranges for specific coal characteristics, such as heat content, sulfur, ash and moisture content as well as others. Failure to meet these specifications can result in economic penalties, suspension or cancellation of shipments or termination of the agreements.

Our coal supply agreements also typically contain force-majeure provisions allowing temporary suspension of performance by us or our customers in the event that circumstances beyond the control of the affected party occur, including events such as strikes, adverse mining conditions, mine closures or serious transportation problems that affect us or unanticipated plant outages that may affect the buyer. Our agreements also generally provide that in the event a force-majeure event exceeds a certain time period, the unaffected party may have the option to terminate the purchase or sale in whole or in part.

Transportation

We ship our coal to domestic customers by means of railcars, barges or trucks, or a combination of these means of transportation. We generally sell coal free on board at the mine or nearest loading facility. Our customers normally bear the costs of transporting coal by rail or barge. Historically, most domestic electricity generators have arranged long-term shipping agreements with rail or barge companies to assure stable delivery costs. Approximately 65% of our coal shipped in 2016 was

delivered by barge, which is generally less expensive than transporting coal by truck or rail. The Armstrong Dock, which is located on the Green River, can load up to six million tons of coal annually for shipment on inland waterways. In 2016, approximately 16% and 19% of our coal sales tonnage was shipped by truck and rail, respectively.

Competition

The coal industry is highly competitive. There are numerous large and small producers in all coal producing regions of the United States, and we compete with many of these producers. Our main competitors include Alliance Resource Partners, L.P., Peabody, Foresight Energy L.P., and Murray Energy Corp., all of which are companies mining in the Illinois Basin. Many of these coal producers have greater financial resources and more proven and probable reserves than we do. Based on data from the Mine Safety and Health Administration (MSHA), we were the sixth largest producer of Illinois Basin coal in fiscal 2016, producing approximately 6% of the total Illinois Basin coal. Outside of the Illinois Basin, we compete broadly with other United States based producers of thermal coal and internationally with numerous global coal producers.

The most important factors on which we compete are price, quality and characteristics, transportation costs and reliability of supply. The demand for our coal and the prices that we will be able to obtain for our coal are closely related to coal consumption patterns of the U.S. electric generation industry and international consumers. The patterns of coal consumption are affected by various factors beyond our control, including economic conditions; temperatures in the United States; government regulation; technological developments; and the location, quality, price and availability of competing sources of fuel such as natural gas, oil and nuclear sources, as well as alternative energy sources such as hydroelectric power and wind.

Suppliers

We use various supplies and raw materials in our coal mining operations, such as petroleum-based fuels, explosives, tires and steel, as well as spare parts and other consumables. We use third-party suppliers for a significant portion of our equipment rebuilds and repairs, drilling services and construction. We use sole source suppliers for certain parts of our business, such as explosives and fuel, and preferred suppliers for other parts at our business, such as dragline and shovel parts and related services. We believe adequate substitute suppliers are available.

Employees

At December 31, 2016, we employed approximately 637 employees, none of whom is represented for collective bargaining by a union. We believe that our relations with all employees are good, and, since our inception, we have had no history of work stoppages or union organizing campaigns.

Seasonality

Our business has historically experienced some variability in its results due to the effect of seasons. Demand for coal-fired power can increase due to unusually hot or cold weather as power consumers use more air conditioning or heating. Conversely, mild weather can result in softer demand for our coal. Adverse weather conditions, such as floods or blizzards, can affect our ability to mine and ship our coal and our customers' ability to take delivery of coal.

Regulation and Laws

Federal, state and local authorities regulate the U.S. coal mining industry with respect to matters such as:

- employee health and safety;
- permitting and licensing requirements;
- air quality standards;
- water pollution;
- storage, treatment and disposal of wastes;
- protection of plant life and wildlife, including endangered or threatened species;
- reclamation and restoration of mining properties after mining is completed;

- remediation of contaminated soil and groundwater;
- surface subsidence from underground mining;
- the effects of mining on surface and groundwater quality and availability; and
- competing uses of adjacent, overlying or underlying lands, pipelines, roads and public facilities.

The costs of compliance with these laws and regulations have been and are expected to continue to be significant. Future laws, regulations or orders, as well as differing interpretations and more rigorous enforcement of existing laws, regulations or orders in the future, may substantially increase equipment and operating costs, result in delays and disrupt operations or termination of operations, the extent of which cannot be predicted with any degree of certainty. We are committed to operating our mines in compliance with applicable federal, state and local laws and regulations. However, because of extensive and comprehensive regulatory requirements, violations during mining operations occur from time to time. Violations, including violations of any permit or approval, can result in substantial civil and criminal fines and penalties, including revocation or suspension of permits required for mining. None of the violations we have experienced to date or the monetary penalties assessed have had a material impact on our operations.

In addition, our customers are subject to extensive regulation regarding the environmental impacts associated with the combustion or other use of coal, which could affect demand for our coal. Changes in applicable laws or the adoption of new laws relating to energy production may cause coal to become a less attractive source of energy, which may adversely affect our mining operations, cost structure or the demand for coal. For example, if emissions rates or caps on greenhouse gases are enacted or a tax on carbon is imposed, the market share of coal as fuel used to generate electricity would be expected to decrease.

The Company is continuously monitoring actions by the regulatory agencies that govern coal mining operations, as potential changes within such agencies as a result of the 2016 presidential and Congressional elections may result in revisions and amendments to certain of the environmental initiatives discussed below.

Mine Safety and Health Laws

Stringent health and safety standards have been in effect since the enactment of the Federal Coal Mine Health and Safety Act of 1969. The Federal Mine Safety and Health Act of 1977 (the Mine Act) provided for MSHA and significantly expanded the enforcement of safety and health standards and imposed safety and health standards on all aspects of mining operations. It requires regular inspections of surface and underground coal mines and the issuance of citations or orders for violations of mandatory health and safety standards. Serious violations of mandatory health and safety standards or circumstances deemed to constitute an imminent danger to health or safety may result in the issuance of an order requiring the immediate withdrawal of miners from the mine or shutting down a mine or any section of a mine or any piece of mine equipment. The Mine Act also imposes criminal liability for corporate operators who knowingly falsify records required to be kept under the Mine Act or who knowingly or willfully violate a mandatory health and safety standard or order and provides that civil and criminal penalties may be assessed against individual agents, officers and directors who knowingly or willfully violate a mandatory health and safety standard or order. The State of Kentucky also has programs for mine safety and health regulation and enforcement. Collectively, federal and state safety and health regulation in the coal mining industry provides one of the most comprehensive systems for protection of employee health and safety affecting any segment of U.S. industry. In the wake of several recent underground mine accidents, enforcement scrutiny has also increased, including increased number of inspections, more inspection hours at mine sites and increased number and severity of enforcement actions. Such regulation and enforcement has a significant effect on our operating costs.

In 2006, in response to an increase in fatal mine accidents, Congress enacted the Federal Mine Improvement and New Emergency Response Act of 2006 (the MINER Act). Among other things, the MINER Act: (i) imposed additional obligations on coal operators related to (a) developing new emergency response plans that address post-accident communications, tracking of miners, breathable air, lifelines, training and communication with local emergency response personnel; (b) establishing additional requirements for mine rescue teams; and (c) notifying federal authorities of incidents that pose a reasonable risk of death; and (ii) increased penalties for violations of applicable federal laws and regulations.

Subsequent to passage of the MINER Act, Kentucky and several other states enacted legislation addressing issues such as mine safety and accident reporting, increased civil and criminal penalties and increased inspections and oversight.

On January 23, 2013, MSHA published a revision to the pattern of violations (POV) regulation allowing, among other things, the use of non-final citations and orders in determining whether a pattern of violations exists at a coal mine. Under the new rule, citations and orders which an operator has challenged but that have not yet been adjudicated may nonetheless be used to determine that a pattern of violations exists at a mine. If a POV notice is issued to a mine operator, each subsequent significant and substantial violation results in a withdraw order until the violation is abated. The revised POV regulation also eliminated the "potential pattern of violations" (PPOV) designation along with the subsequent period during with a mine receiving PPOV notice could regain compliance before receiving a POV notice.

On April 23, 2014, MSHA published a final rule, which, among other things, reduces the overall respirable coal dust standard from 2.0 mg to 1.5 mg per cubic meter of air and cuts in half the standard from 1.0 to 0.5 for certain mine entries and miners with pneumoconiosis. The rule also increases sampling requirements, requires use of continuous personal dust monitors (CPDMs) to provide real-time information about dust levels and requires immediate corrective action when a single, full-shift sample finds an excessive concentration of dust. Legal challenges to the rule have been unsuccessful, and as of August 1, 2016, the rule has been fully implemented.

On January 15, 2015, MSHA published a final rule requiring underground coal mine operators to equip continuous mining machines, except full-face continuous mining machines, with proximity detection systems. This final rule is intended to strengthen protections for miners by reducing the potential for pinning, crushing or striking accidents in underground coal mines. The new rule was effective March 16, 2015, but has staggered implementation deadlines through early 2018 depending upon the manufacturing date of the equipment and whether or not the equipment has been previously equipped with a proximity detection system.

On September 2, 2015, MSHA published a proposed rule requiring underground coal mine operators to equip all haulage equipment and scoops on non-longwall sections with proximity detection systems. The comment period closed, and a final rule was expected in 2016; however, on January 9, 2017, MSHA reopened the comment period for 30 days. Given the reopened comment period, it is unclear when a final rule will be issued. Based upon the proposed rule, the final rule is expected to have a staggered implementation schedule from 8 to 36 months after the effective date of the final rule.

Our compliance with current or future mine health and safety regulations could increase our mining costs. At this time, it is not possible to predict the full effect that the new or proposed statutes, regulations and policies will have on our operating costs, but if they increase our costs, they will also increase the costs of our competitors. Some, but not all, of these additional costs may be passed on to our customers.

Workers' Compensation

We provide income replacement and medical treatment for work-related traumatic injury claims as required under state workers' compensation laws. Our costs will vary based on the number of accidents that occur at our mines and other facilities and our costs of addressing these claims. We provide benefits to our employees by being insured through state-sponsored programs or an insurance carrier where there is no state-sponsored program.

Black Lung

Under the Black Lung Benefits Revenue Act of 1977 and the Black Lung Benefits Reform Act of 1977, as amended in 1981, each coal mine operator must pay federal black lung benefits to eligible current and former employee claimants and also make payments to a trust fund for the payment of benefits and medical expenses to eligible claimants who last worked in the coal industry prior to January 1, 1973. The trust fund is funded by an excise tax on production of up to $1.10 per ton for coal mined via underground mining methods and up to $0.55 per ton for coal mined via surface mining methods, neither amount to exceed 4.4% of the gross sales price. The excise tax does not apply to coal shipped outside the United States. We recorded $5.0 million and $6.3 million of expense related to this excise tax in 2016 and 2015, respectively.

With the implementation of the Patient Protection and Affordable Care Act in 2010 and the amendment of federal black lung regulations, the number of claimants who are awarded federal black lung benefits has increased and will likely continue to increase, as will the amounts of those awards. Our payment obligations for federal black lung benefits are either secured by insurance coverage or paid from a tax exempt trust established for that purpose. Based on required funding levels, we may have to supplement the trust corpus to cover the anticipated liabilities going forward. In addition, we could be held liable under various state statutes for black lung claims.

Mining Permits and Approval

Numerous governmental permits and approvals are required for our coal mining operations. When we apply for some of these permits, we are required to assess the effect or impact that any proposed production or processing of coal may have on the environment. The authorization and permitting requirements imposed by governmental authorities are costly and may delay or prevent commencement or continuation of mining operations in certain locations. These permitting requirements may also be supplemented, modified or re-interpreted from time to time. Past or ongoing violations of federal and state mining laws could provide a basis to modify or revoke existing permits and to deny the issuance of additional permits.

In order to obtain the permits and approvals necessary for mining from federal and state regulatory authorities, mine operators or applicants must submit a reclamation plan for restoring the mined land to its prior productive use, better condition or other approved use. Typically, we submit the necessary permit applications several months, or even years, before we plan to mine a new area. Some required permits for mining have become increasingly difficult to obtain in a timely manner, or at all, particularly those permits involving the federal Clean Water Act (CWA) and the U.S. Army Corps of Engineers (Corps). Specifically, issuance of Corps permits allowing placement of material in valleys or streams has been slowed in recent years due to ongoing disputes over the requirements for obtaining such permits. While we do not engage in mountaintop mining, we are required to obtain permits from the Corps, and our mining operations do affect bodies of water regulated by the Corps. The permit application review process takes longer to complete, and permit applications are increasingly being challenged by environmental and other advocacy groups, although we are not aware of any such challenges to any of our pending permit applications. We may experience difficulty or delays in obtaining the permits or other approvals necessary for mining in the future or even face denials of permits altogether. Violations of federal, state and local laws, regulations or any permit, order, or approval issued under such authorization can result in substantial fines and penalties, including modification, revocation or suspension of mining permits and, in certain circumstances, criminal sanctions.

Surface Mining Control and Reclamation Act

The Surface Mining Control and Reclamation Act of 1977 (SMCRA), which is administered by the Office of Surface Mining Reclamation and Enforcement within the Department of the Interior (OSM), establishes operational, reclamation and closure standards for all aspects of surface mining, including the surface effects of underground coal mining. Mining operators must obtain SMCRA permits and permit renewals from OSM or from the applicable state agency if the state has obtained primacy. A state may achieve primacy if it develops a regulatory program that is no less stringent than the federal program and approved by OSM. Our mines are located in Kentucky, which has primacy to administer the SMCRA program. SMCRA stipulates compliance with many other major environmental statutes, including the federal Clean Air Act (CAA), the CWA, the Resource Conservation and Recovery Act (RCRA) and the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA or Superfund).

Some SMCRA mine permits take us over a year to prepare, depending on the size and complexity of the mine. Once a permit application is prepared and submitted to the regulatory agency, it goes through a completeness and technical review. Also, before a SMCRA permit is issued, a mine operator must submit a bond or otherwise secure the performance of all reclamation obligations. After the application is submitted, public notice or advertisement of the proposed permit action is required, which is followed by a public comment period. It is not uncommon for it to take more than a year for a SMCRA mine permit to be issued.

The OSM's "stream buffer zone rule" (SBZ Rule) prohibits mining disturbances within 100 feet of streams if there would be a negative effect on water quality. In December 2008, the OSM finalized a revised SBZ Rule, which purported to clarify certain aspects of the SBZ Rule; however, the U.S. District Court for the District of Columbia struck down the revised SBZ Rule in early 2014. As such, the 1983-era SBZ rule remains in place pending further action by OSM to proceed with new rulemaking.

On June 11, 2009, the Secretary of the Department of the Interior, the Administrator of the EPA, and the Acting Assistant Secretary of the Army for Civil Works entered into a memorandum of understanding to reduce the environmental impacts of surface coal mining operations in certain Appalachian states, committing OSM to revising provisions of current SMCRA regulations, including the SBZ rule. On July 27, 2015, OSM published its proposed Stream Protection Rule (SPR). The SPR proposed extensive revisions to the current regulation of coal mining, including but not limited to, changes to bonding requirements, "approximate original contour" requirements, subsidence restrictions, and post-mining restoration requirements. The proposal included newly defined terms and concepts such as "material damage to the hydrologic balance outside the permit area," new monitoring and data collection requirements, stream restoration requirements and new procedures and requirements related to the protection of threatened or endangered species under the federal Endangered Species Act.

The final SPR was published in the Federal Register on December 20, 2016, with an effective date of January 19, 2017. On January 17, 2017, thirteen states sued the Department of the Interior seeking to invalidate the rule and enjoin its enforcement. In February 2017, both the U.S. House of Representatives and the Senate passed resolutions disapproving the SPR under the Congressional Review Act. President Trump signed legislation repealing the SPR on February 16, 2017. Whether Congress or the states will enact future legislation with requirements similar to, or more stringent than, the SPR remains uncertain.

Surety Bonds

Federal and state laws require a mine operator to secure the performance of its reclamation obligations required under SMCRA through the use of surety bonds or other approved forms of performance security to cover the costs the state would incur if the mine operator was unable to fulfill its obligations. The cost of surety bonds have fluctuated in recent years, and the market terms of these bonds have generally become more unfavorable to mine operators. For example, in connection with our current bonds, we are required to post substantial security in the form of cash collateral. These changes in the terms of the bonds have been accompanied at times by a decrease in the number of companies willing to issue surety bonds. Some mine operators have therefore used letters of credit to secure the performance of a portion of their reclamation obligations. Many of these bonds are renewable on a yearly basis. We cannot predict our ability to obtain bonds or other approved forms of performance security, or the cost of such security, in the future. As of December 31, 2016, we had approximately $32.2 million in surety bonds outstanding to secure the performance of our reclamation obligations, which are collateralized by cash deposits of approximately $6.0 million.

In addition to the bond requirement for an active or proposed permit, the Abandoned Mine Land Fund, which was created by SMCRA, imposes a fee on all coal produced in the United States. The proceeds of the fee are used to restore mines closed or abandoned prior to SMCRA's adoption in 1977 and to pay health care benefit costs of orphan beneficiaries of the Combined Fund created by the Coal Industry Retiree Health Benefit Act of 1992. Currently and through 2021, the fee is $0.28 per ton for coal mined via surface mining methods and $0.12 per ton on coal via underground mining methods. In 2016 and 2015, we recorded approximately $1.1 million and $1.5 million, respectively, of expense related to these reclamation fees.

In January 2011, OSM determined that the Kentucky regulatory program contained several reclamation bonding deficiencies. During May 2012, OSM required the implementation of program changes to address the deficiencies. Prominent among those changes was the promulgation of legislation that established the Kentucky Reclamation Guaranty Fund (RGF), the RGF Commission and the Office of the RGF, to support the commission and administer its affairs. The RGF is a revolving, interest-bearing account that will provide financial assistance in the event the permit-specific reclamation bond is insufficient to complete reclamation on a mine site. Participation in the RGF is mandatory, unless permittees elect to provide a full-cost bond in accordance with specific calculation methods. The RGF received initial capitalization from the assets of the former voluntary Kentucky Bond Pool, which was abolished by the new legislation. A start-up assessment and a one-time acreage fee provided additional initial capitalization. Beginning January 2014, additional revenue for the RGF is generated from tonnage and acreage fees paid annually, depending on the operational status of each permit.

Air Emissions

A. General Air Quality Regulations

The CAA, the amendments thereto, and state laws that regulate air emissions affect coal mining operations, both directly and indirectly. Direct impacts on our coal mining and processing operations include CAA permitting requirements and control requirements for particulate matter, which includes fugitive dust from roadways, parking lots and equipment such as conveyors and storage piles. The CAA also indirectly affects coal mining operations by extensively regulating the emissions of particulate matter, sulfur dioxide (SO2), nitrogen oxide (NOx), carbon monoxide, ozone, mercury and other compounds emitted by coal-fired power plants, which are the largest end users of our coal. Costs to comply with current, new and emerging regulations applicable to coal-fired power plants could have an adverse effect on our customers, thereby reducing demand for coal. Moreover, these regulations may cause some users of coal to switch from coal to natural gas or renewable energy for electric power generation.

In addition to the greenhouse gas (GHG) issues discussed below, the air emissions programs that may directly or indirectly impact our operations include, but are not limited to, the following:

- The EPA's Acid Rain Program under the CAA regulates emissions of SO2, a by-product of coal combustion, from electric generating facilities. Affected facilities purchase or are otherwise allocated SO2 emissions allowances, which must be surrendered annually in an amount equal to a facility's SO2 emissions in that year. Facilities may sell or trade excess allowances to other facilities that require additional allowances to offset their SO2 emissions. In addition to

purchasing or trading for additional SO2 allowances, affected power facilities can satisfy the requirements of the EPA's Acid Rain Program by switching to lower-sulfur fuels, installing pollution control devices such as flue gas desulfurization systems, or "scrubbers," or by reducing electricity generating levels.

- The Clean Air Interstate Rule (CAIR) calls for power plants in 28 states and Washington, D.C. to reduce emission levels of SO2 and NOx pursuant to a cap-and-trade program similar to the system in effect for acid rain. In June 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR), a replacement rule for CAIR, which requires 28 states in the Midwest and Eastern seaboard to reduce power plant SO2 and NOx emissions that cross state lines and contribute to ozone and/or fine particle pollution in other states. Though some issues with CSAPR remain subject to litigation, the EPA began implementation of CSAPR's Phase 1 emission reduction requirements on January 1, 2015, and Phase 2 limits governing annual SO2 and NOx emissions took effect on January 1, 2017. On September 7, 2016, the EPA finalized an update to CSAPR which would reduce summertime NOx emissions from power plants in 22 states in the Eastern U.S. These season limits for NOx are scheduled to become effective on May 1, 2017. The final impact of CSAPR are unknown at the present time due to the implementation of Mercury and Air Toxic Standards (MATS), discussed below, the recent updates to CSAPR and the significant number of coal retirements that have resulted and that potentially will result from MATS.

- In February 2012, the EPA adopted the MATS, which regulates the emission of mercury and other metals, fine particulates, and acid gases such as hydrogen chloride from coal and oil-fired power plants. In March 2013, the EPA finalized a reconsideration of the MATS rule as it pertains to new power plants, principally adjusting emissions limits to levels attainable by existing control technologies. Appeals were filed and oral arguments were heard by the D.C. Circuit Court of Appeals in December 2013. On April 15, 2014, the D.C. Circuit Court of Appeals upheld MATS. On June 29, 2015, the Supreme Court remanded the final rule back to the D.C. Circuit holding that the agency must consider cost before deciding whether regulation is necessary and appropriate. On December 1, 2015, the EPA issued, for comment, the proposed Supplemental Finding. The EPA issued the Supplemental Finding on April 15, 2016, finding that the rule was necessary and appropriate despite the costs. Regardless of the various court actions, many electric generators had already announced retirements due to the MATS rule. MATS would force generators to make capital investments to retrofit power plants and could lead to additional retirements of older coal-fired generating units. The announced and possible additional retirements are likely to reduce the demand for coal. Apart from MATS, several states have enacted or proposed regulations requiring reductions in mercury emissions from coal-fired power plants, and federal legislation to reduce mercury emissions from power plants has been proposed. Regulation of mercury emissions may decrease the future demand for coal. We continue to evaluate the possible scenarios associated with CSAPR and MATS and the effects they may have on our business and our results of operations, financial condition or cash flows.

- In January 2013, the EPA issued final Maximum Achievable Control Technology (MACT) standards for several classes of boilers and process heaters, including large coal-fired boilers and process heaters (Boiler MACT), which require owners of industrial, commercial, and institutional boilers to comply with standards for air pollutants, including mercury and other metals, fine particulates, and acid gases such as hydrogen chloride. Businesses and environmental groups have filed legal challenges to Boiler MACT and petitioned the EPA to reconsider the rule. On December 1, 2014, the EPA announced reconsideration of the standard and will accept public comment on five issues for its standards on area sources, will review three issues related to its major-source boiler standards, and four issues relating to commercial and solid waste incinerator units. Before reconsideration, the EPA estimated the rule will affect 1,700 existing major source facilities with an estimated 14,316 boilers and process heaters. While some owners would make capital expenditures to retrofit boilers and process heaters, a number of boilers and process heaters could be prematurely retired. Retirements are likely to reduce the demand for coal. The impact of the regulations will depend on the EPA's reconsideration and the outcome of ongoing and subsequent legal challenges.

- The EPA is required by the CAA to periodically re-evaluate the available health effects information to determine whether the national ambient air quality standards (NAAQS) should be revised. As a result of this process, the EPA has adopted more stringent NAAQS for fine particulate matter, ozone, SO2 and NOx. As a result, some states will be required to amend their existing individual state implementation plans (SIPs) to achieve and compliance with the new air quality standards. Other states will be required to develop new SIPs for areas that were previously in "attainment," but do not meet the revised standards. In addition, under the revised ozone NAAQS, significant additional emissions control expenditures may be required at coal-fired power plants. Attainment dates for the new standards range between 2013 and 2030, depending on the severity of the non-attainment. The final rule has been challenged in litigation by industry and state petitioners and several environmental groups, some aspects of which have been vacated and some of which have been remanded to the EPA for further consideration. The final rules and new standards may impose additional emissions control requirements on new and expanded coal-fired power plants and industrial boilers.

Because coal mining operations and coal-fired electric generating facilities emit particulate matter and SO2, our mining operations and our customers could be affected when the new standards are implemented by the applicable states, and developments might indirectly reduce the demand for coal.

- The EPA's regional haze program is designed to protect and improve visibility at and around national parks, national wilderness areas and international parks. Under the program, states are required to develop SIPs to improve visibility. Typically, these plans call for reductions in SO2 and NOx emissions from coal-fueled electric plants. In recent cases, the EPA has decided to negate the SIPs and impose stringent requirements through federal implementation plans (FIPs). The regional haze program, including particularly the EPA's FIPs, and any future regulations may restrict the construction of new coal-fired power plants whose operation may impair visibility at and around federally protected areas and may require some existing coal-fired power plants to install additional control measures designed to limit haze-causing emissions. These requirements could limit the demand for coal in some locations.

- The EPA's new source review (NSR) program under the CAA in certain circumstances requires existing coal-fired power plants, when modifications to those plants significantly increase emissions, to install more stringent air emissions control equipment. The Department of Justice, on behalf of the EPA, has filed lawsuits against a number of coal-fired electric generating facilities alleging violations of the NSR program. The EPA has alleged that certain modifications have been made to these facilities without first obtaining certain permits issued under the program. Several of these lawsuits have settled, but others remain pending. Depending on the ultimate resolution of these cases, demand for coal could be affected.

B. Greenhouse Gas Regulations

Carbon dioxide (CO2) is a GHG, the man-made emission of which is of major concern under any regulatory framework intended to control what is sometimes referred to "climate change." CO2 is a major by-product of the combustion process within coal-fired power plants. Methane, which must be expelled from our underground coal mines for mining safety reasons, is also classified as a GHG.

Future regulation of GHGs in the United States could occur pursuant to, for example, future U.S. treaty commitments; new domestic legislation that imposes a tax on GHG emissions, a GHG cap-and-trade program or other programs aimed at GHG reduction; or regulatory programs that may be established by the EPA. Internationally, the Kyoto Protocol set binding emission targets for developed countries that ratified it (the U.S. did not ratify, and Canada officially withdrew from its Kyoto commitment in 2012) to reduce their global GHG emissions. The Kyoto Protocol was nominally extended past its expiration date of December 2012, with a requirement for a new legal construct to be put into place by 2015. Most recently, the United Nations Framework Convention on Climate Change met in Paris, France in December 2015 and agreed to an international climate agreement. Although this agreement does not create any binding obligations for nations to limit their GHG emissions, it does include pledges to voluntarily limit or reduce future emissions. These commitments could further reduce demand and prices for our coal. The U.S. is currently a party to the Paris agreement; however, whether the U.S. will remain a party is uncertain given President Trump's statements regarding cancellation of U.S. participation. Notwithstanding this uncertainty, many states, regions and governmental bodies have adopted GHG initiatives and have or are considering the imposition of fees or taxes based on the emission of GHGs by certain facilities, including coal-fired electric generating facilities. Depending on the particular regulatory program that may be enacted, at either the federal or state level, the demand for coal could be negatively impacted, which would have an adverse effect on our operations.

Even in the absence of new federal legislation, the EPA has already begun to regulate GHG emissions under the CAA. In 2009, the EPA issued a final rule, known as the Endangerment Finding, declaring that GHG emissions, including CO2 and methane, endanger public health and welfare.

In May 2010, the EPA issued its final "tailoring rule" for GHG emissions, a policy aimed at shielding small emission sources from CAA permitting requirements. The EPA's rule phases in various GHG-related permitting requirements beginning in January 2011. Beginning July 1, 2011, the EPA requires facilities that must already obtain NSR permits for other pollutants to include GHGs in their permits for new construction projects that emit at least 100,000 tons per year of GHGs and existing facilities that increase their emissions by at least 75,000 tons per year. These permits require that the permittee adopt the Best Available Control Technology (BACT). In June 2012, the D.C. Circuit Court of Appeals upheld these permitting regulations. In June 2014, the U.S. Supreme Court invalidated the EPA's position that power plants and other sources can be subject to permitting requirements based on their GHG emissions alone. For CO2 BACT to apply, CAA permitting must be triggered by another regulated pollutant, such as SO2. As a result of litigation filed by industry groups, the D.C. Circuit ordered the EPA regulations under review to be vacated, with certain limitations. On August 19, 2015, the EPA issued a final rule amending its regulations to remove portions of those regulations that were vacated by the D.C. Circuit. Currently the impacts are uncertain.

As a result of revisions to its preconstruction permitting rules that became fully effective in 2011, the EPA is now requiring new sources, including coal-fired power plants, to undergo control technology reviews for GHGs as a condition of permit issuance. These reviews may impose limits on GHG emissions, or otherwise be used to compel consideration of alternative fuels and generation systems, as well as increase litigation risk for-and so discourage development of-coal-fired power plants.

In March 2012, the EPA proposed New Source Performance Standards (NSPS) for CO2 emissions from new fossil fuel-fired power plants. The proposal requires new coal units to meet a CO2 emissions standard of 1,000 lbs. CO2/MWh, which is equivalent to the CO2 emitted by a natural gas combined cycle unit. In January 2014, the EPA formally published its re-proposed NSPS for CO2 emissions from new power plants. The re-proposed rule requires an emissions standard of 1,100 lbs. CO2/MWh for new coal-fired power plants. To meet such a standard, new coal plants would be required to install carbon capture and storage (CCS) technology. In August 2015, the EPA released final rules requiring newly constructed coal-fired steam electric generating units (EGUs) to emit no more than 1,400 lbs. CO2/MWh (gross) and be constructed with CCS to capture 16% of CO2 produced by an electric generating unit burning bituminous coal. At the same time, the EPA finalized GHG emissions regulations for modified and existing power plants. The rule for modified sources required reducing GHG emissions from any modified or reconstructed source and could limit the ability of generators to upgrade coal-fired power plants, thereby reducing the demand for coal. The rule for existing sources proposes to establish different target emission rates (lbs. per megawatt hour) for each state and has an overall goal to achieve a 32% reduction of CO2 emissions from 2005 levels by 2030. The compliance period begins in 2022, and in 2030, CO2 emissions goals must be met. Collectively, these requirements have led to premature retirements and could lead to additional premature retirements of coal-fired generating units and reduce the demand for coal. Congress has rejected legislation to restrict CO2 emissions from existing power plants, and it is unclear whether the EPA has the legal authority to regulate CO2 emissions for existing and modified power plants without additional Congressional authority. Challenges to the rule by a number of states and industry groups are pending before the D.C. Circuit Court of Appeals. On March 28, 2017, President Trump signed an executive order requiring the EPA to review the CPP, a first step in rolling back the CPP.

In June 2014, the EPA proposed CO2 emission “guidelines” for modified and existing fossil fuel-fired power plants known as the Clean Power Plan (CPP). The CPP was finalized in August 2015 and established carbon pollution standards for power plants, called CO2 emission performance rates. The EPA expects each state to develop implementation plans for power plants in its state to meet the individual state targets established in the CPP. The EPA has given states the option to develop compliance plans for annual rate-based reductions (pounds per megawatt hour) or mass-based tonnage limits for CO2. The state plans were due in September 2016, subject to potential extensions of up to two years for final plan submission. The compliance period begins in 2022, and emission reductions will be phased in up to 2030. The EPA also proposed a federal compliance plan to implement the CPP in the event that an approvable state plan is not submitted to the EPA. Although each state can determine its own method of compliance, the requirements rely on decreased use of coal and increased use of natural gas and renewables for electricity generation, as well as reductions in the amount of electricity used by consumers. Judicial challenges have been filed. On February 9, 2016, the U.S. Supreme Court issued a stay, halting implementation of the regulations. The stay will be in place until the D.C. Circuit Court of Appeals rules on the merits of the legal challenges and, if following a ruling by the D.C. Circuit Court of Appeals, a writ of certiorari from the Supreme Court is sought and granted, the stay will remain in place until the Supreme Court issues its decision on the merits. If, despite the legal challenges, the rules are implemented in their current form, demand for coal will likely be further decreased, potentially significantly, and adversely impact our business.

On June 28, 2010, the EPA issued the Final Mandatory Reporting of Greenhouse Gases Rule requiring all stationary sources that emit more than 25,000 tons of GHGs per year to collect and report annually to the EPA data regarding such emissions occurring after January 1, 2010. These GHG rules affect many of our customers, as well as additional source categories, including all underground mines subject to quarterly methane sampling by MSHA. Underground mines subject to these rules, including ours, were required to begin monitoring GHG emissions on January 1, 2011 and began reporting to the EPA in 2012.

In October 2013, the U.S. Supreme Court granted a number of petitions for certiorari seeking review of the EPA’s approach to GHG regulation. The Supreme Court heard oral arguments in February 2014. On June 23, 2014, the Supreme Court issued an opinion affirming the D.C. Circuit decision in part and reversing the decision in part. The Court struck down the EPA’s tailoring rule, making permanent a temporary exclusion that the EPA had provided for small sources. However, the Court’s holding affirmed the EPA’s authority to regulate GHG emissions from the vast majority of sources subject to the CAA’s permitting provisions, and did not affect the EPA’s ability to regulate GHG emissions from new and existing sources. Future legislation or new regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. Substantial limitations on GHG emissions could adversely affect demand for the coal we produce.

There have been numerous protests of and challenges to the permitting of new coal-fired power plants by environmental organizations and state regulators for concerns related to GHG emissions. For instance, various state regulatory authorities have rejected the construction of new coal-fueled power plants based on the uncertainty surrounding the potential costs associated with GHG emissions from these plants under future laws limiting the emissions of CO2. In addition, several permits issued to new coal-fueled power plants without limits on GHG emissions have been appealed to the EPA's Environmental Appeals Board.

In addition, over 30 states have currently adopted "renewable energy standards" or "renewable portfolio standards," which encourage or require electric utilities to obtain a certain percentage of their electric generation portfolio from renewable resources by a certain date. These standards range generally from 10% to 30%, over time periods that generally extend from the present until between 2020 and 2030. Many states have now begun re-visiting some of these standards and have adjusted or in some cases revoked these standards. To the extent these requirements remain in place and potentially affect our current and prospective customers, they may reduce the demand for coal-fired power, and may affect long-term demand for our coal.

Finally, a federal appeals court allowed a lawsuit pursuing federal common law claims to proceed against certain utilities on the basis that they may have created a public nuisance due to their emissions of CO2, while a second federal appeals court dismissed a similar case on procedural grounds. The U.S. Supreme Court overturned that decision in June 2011, holding that federal common law provides no basis for public nuisance claims against utilities due to their CO2 emissions. The Supreme Court did not, however, decide whether similar claims can be brought under state common law. As a result, despite this favorable ruling, tort-type liabilities remain a concern.

In addition, environmental advocacy groups have filed a variety of judicial challenges claiming that the environmental analyses conducted by federal agencies before granting permits and other approvals necessary for certain coal activities do not satisfy the requirements of the National Environmental Policy Act (NEPA). These groups assert that the environmental analyses in question do not adequately consider the climate change impacts of these particular projects. In December 2014, the Council on Environmental Quality released updated draft guidance discussing how federal agencies should consider the effects of GHG emissions and climate change in their NEPA evaluations. The guidance encourages agencies to provide more detailed discussion of the direct, indirect, and cumulative impacts of a proposed action's reasonably foreseeable emissions and effects. This guidance could create additional delays and costs in the NEPA review process or in our operations, or even an inability to obtain necessary federal approvals for our future operations, including due to the increased risk of legal challenges from environmental groups seeking additional analysis of climate impacts. These arguments, though, have generally not yet been successful in stopping infrastructure and other projects.

Many states and regions have adopted GHG initiatives and certain governmental bodies have or are considering the imposition of fees or taxes based on the emission of GHG by certain facilities, including coal-fired electric generating facilities. For example, in 2005, ten Northeastern states entered into the Regional Greenhouse Gas Initiative agreement (RGGI), calling for implementation of a cap-and-trade program aimed at reducing CO2 emissions from power plants in the participating states. The members of RGGI have established a CO2 trading program. Auctions for CO2 allowances under the program began in September 2008. Though New Jersey withdrew from RGGI in 2011, since its inception, several additional Northeastern states and Canadian provinces have joined as participants or observers.

Following the RGGI model, five Western states launched the Western Regional Climate Action Initiative to identify, evaluate, and implement collective and cooperative methods of reducing GHG in the region to 15% below 2005 levels by 2020. These states were joined by two additional states and four Canadian provinces and became collectively known as the Western Climate Initiative Partners. However, in November 2011, six states withdrew, leaving California and the four Canadian provinces as members. At a January 2012 stakeholder meeting, this group confirmed a commitment and timetable to create the largest carbon market in North America and provide a model to guide future efforts to establish national approaches in both Canada and the U.S. to reduce GHG emissions. It is likely that these regional efforts will continue.

It is possible that future international, federal and state initiatives to control GHG emissions could result in increased costs associated with coal production and consumption, such as costs to install additional controls to reduce CO2 emissions or costs to purchase emissions reduction credits to comply with future emissions trading programs. Such increased costs for coal consumption could result in some customers switching to alternative sources of fuel, or otherwise adversely affect our operations and demand for our products, which could have a material adverse effect on our business, financial condition and results of operations.

Water Discharge

The CWA and corresponding state and local laws and regulations affect coal mining operations by restricting the discharge of pollutants, including the discharge of dredged or fill materials, into waters of a state or of the United States. The

CWA provisions and associated state and federal regulations are complex and subject to amendments, legal challenges and changes in implementation. Recent court decisions, regulatory actions and proposed legislation have created uncertainty over CWA jurisdiction and permitting requirements that could either increase or decrease our costs and time spent on CWA compliance.

CWA requirements that may directly or indirectly affect our operations include the following:

- *Wastewater Discharge.* Section 402 of the CWA regulates the discharge of pollutants into navigable waters of the United States. The National Pollutant Discharge Elimination System (NPDES) requires a permit for any such discharges and entails regular monitoring, reporting and compliance with performance standards, all of which are preconditions for the issuance and renewal of NPDES permits that govern the discharge of pollutants into jurisdictional waters. Failures to comply with the CWA or the NPDES permits can lead to the suspension or revocation of permits, the imposition of penalties, compliance costs and delays in coal production. The CWA and corresponding state laws also protect waters that states have designated as impaired (i.e., as not meeting present water quality standards) through Total Maximum Daily Load (TMDL) regulations and "high quality/exceptional use" waters through state anti-degradation regulations, which restrict or prohibit discharges which result in degradation. As part of NPDES permitting, both TMDL and anti-degradation reviews can result in our NPDES permit terms and conditions, including effluent limitations, becoming more stringent, thereby potentially increasing our treatment costs and making it more difficult to obtain new surface mining permits. Permits may also include limitations or other conditions related to pollutants not traditionally included in coal mining NPDES permits, such as chlorides, sulfates, selenium, conductivity, and dissolved solids, thus requiring additional treatment and monitoring of discharges to waters, and may include additional requirements intended to protect the physical, chemical, and biological integrity of waters. Individually and collectively, these requirements may cause us to incur significant additional costs that could adversely affect our operating results, financial condition and cash flows.

- *Dredge and Fill Permits.* Many mining activities, including the development of settling ponds and other impoundments, may require a Section 404 permit from the Corps prior to conducting any such mining activities that involve discharges of "fill" or dredged materials into waters of the United States. The Corps is empowered to issue "nationwide" permits (each, an NWP) for specific categories of filling activities that are determined to have minimal environmental adverse effects in order to save the cost and time of issuing individual permits under Section 404 of the CWA. Using this authority, the Corps issued NWP 21, which authorizes the disposal of dredge-and-fill material from mining activities into the waters of the United States. Individual Section 404 permits are required for activities determined to have more significant impacts to waters of the United States. Since 2003, environmental groups have pursued litigation primarily in West Virginia and Kentucky challenging the validity of NWP 21 and various individual Section 404 permits authorizing valley fills associated with surface coal mining operations (primarily mountain-top removal operations). This litigation has resulted in delays in obtaining these permits and has increased permitting costs. Effective March 2012, the Corps reissued 49 NWPs, including NWP 21, authorizing mining activities in streams and wetlands. The reissued NWP 21 will allow surface mining operations to disturb up to 0.5-acre of waters of the U.S. and 300 linear feet of stream bed. The 300 linear foot limit can be waived by the District Engineer for intermittent and ephemeral streams. Valley fills are specifically excluded from NWP 21. Other NWPs issued in 2012 for coal mining activities include NWPs 44, 49, and 50. In addition, other NWPs can be used for certain impacts to waters associated with coal mining. NWPs are reissued every five years, and the new NWPs were set to become effective on March 19, 2017, replacing the 2012 NWPs. There are some proposed changes to NWPs 21, 44, and 50 - all related to mining activities, with the changes focused on disallowing total impacts greater than ½ acre, and removing language from the 2012 NWP 21 that authorized coal mining activities previously authorized by the 2007 NWP 21. Due to President Trump's regulatory freeze, the effective date of March 19, 2017 will be delayed for at least two days, and it is possible that the NWPs will be submitted for additional public comment. Where an activity does not qualify for a NWP, the applicant must obtain an individual CWA Section 404 permit, which involves a longer and more costly application and review process.

- *Clean Water Rule (CWR).* On June 29, 2015, both the EPA and the Corps jointly proposed a rule defining the scope of waters of the United States to be protected pursuant to the CWA. The CWR was proposed in response to earlier United States Supreme Court rulings interpreting the regulatory scope of the CWA re-defining "Waters of the United States" (WOTUS), and thereby creating uncertainty as to which waters were regulated pursuant to the CWA and which waters were not. The final rule was to become effective on August 28, 2015, and revises and expands regulations that have been in place for decades, and is anticipated to expand areas subject to CWA permitting. Multiple lawsuits were filed promptly challenging the CWR. The CWR is not currently being enforced because of a federal court ruling that blocked its implementation while it is being litigated. Adding to uncertainty surrounding the rule, in December 2015 the Governmental Accountability Office concluded in a report that the EPA had improperly lobbied for the CWR.

The National Mining Association and multiple states have petitioned the Supreme Court seeking a determination of whether the Sixth Circuit Court of Appeals has jurisdiction over the legal challenges to the CWR, or WOTUS rule, and the Sixth Circuit has held its litigation in abeyance, including retaining the stay, pending the Supreme Court's review. A decision by the Supreme Court is anticipated in June 2017.

Since 2009, the EPA has taken a more active role in its review of NPDES permit applications for coal mining operations in Appalachia. In September 2009, for example, the EPA delayed the issuance of 74 Section 404 permits in central Appalachia. In April 2010, the EPA issued an interim guidance document on water quality requirements for coal mines in Appalachia, coinciding with its new practice of actively commenting on and objecting to the issuance of many NPDES permits for coal mining projects, particularly in West Virginia. In January 2011, the EPA exercised its "veto" power under Section 404(c) of the CWA to withdraw or restrict the use of previously issued permits in connection with the Spruce No. 1 Surface Mine in West Virginia, which is one of the largest surface mining operations ever authorized in Appalachia. This action is the first time that such power was exercised with regard to a previously permitted coal mining project. These EPA efforts have extended the time required for operations affected by them to obtain permits for coal mining, and increased the costs associated with obtaining and complying with those permits. Additionally, any future regulatory or policy changes could further restrict our ability to obtain other new permits or to maintain existing permits. Any future use of the EPA's Section 404 "veto" power could create uncertainly with regard to our continued use of current permits.

Resource Conservation and Recovery Act

Enacted in 1976, the Resource Conservation and Recovery Act (RCRA) along with corresponding state laws establish standards for the management of solid and hazardous wastes generated at facilities. RCRA affects both current waste management and disposal practices and some past waste treatment, storage and disposal practices. RCRA generally exempts certain coal mining wastes, such as overburden and coal cleaning wastes from regulation as hazardous wastes. A change in this exemption would have a significant impact on our mining operations.

Although RCRA has the potential to apply to wastes from the combustion of coal, the EPA has determined that most coal combustion wastes do not warrant regulation as hazardous wastes under RCRA. Most state solid waste laws also regulate coal combustion wastes as non-hazardous wastes. On December 19, 2014, the EPA issued a final rule establishing that coal ash would be regulated as non-hazardous waste under RCRA subtitle D, with national minimum criteria for disposal. The rule requires closure of sites that fail to meet prescribed engineering standards, requires regular inspection of impoundments, establishes limits on the location of new sites, and requires immediate remediation and closure of unlined ponds that are polluting ground water. The rule does provide flexibility for states to implement and enforce the rule. The EPA did not address the use of coal combustion wastes as minefill, but indicated that it would separately work with OSM in order to develop effective federal regulations ensuring that such placement is adequately controlled. The regulation of coal ash under RCRA subtitle D could adversely affect our customers and potentially reduce the desirability of coal for them. In addition, contamination caused by the past disposal of coal combustion byproducts, including coal ash, could lead to material liability to our customers under RCRA or other federal or state laws and potentially reduce the demand for coal.

Comprehensive Environmental Response, Compensation and Liability Act

Although typically not applied to the coal mining sector, the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), which was enacted in 1980, and similar state laws may affect coal mining operations by creating liability for investigation and remediation in response to releases of hazardous substances into the environment and for damages to natural resources. Under CERCLA and similar state laws, joint and several liabilities may be imposed on waste generators, site owners, operators, lessees and others, regardless of fault or the legality of the original disposal activity. We are currently unaware of any material liability associated with the release or disposal of hazardous substances from our mine sites.

Endangered Species Act

The federal Endangered Species Act of 1973 and counterpart state legislation (collectively, ESA) protects species threatened with possible extinction. A number of species indigenous to the areas in which we operate are protected under the ESA, and compliance with ESA requirements could increase our costs of operations or have the effect of prohibiting or delaying us from obtaining mining permits. Changes in species listings or requirements under the ESA could result in increased operating costs, heightened difficulty in obtaining future mining permits or the need to implement additional mitigation measures.

Other Environmental Laws

Our business is subject to numerous environmental laws. In addition to those discussed above, our operations can also be subject to the Safe Drinking Water Act, the Toxic Substances Control Act, the National Environmental Policy Act, the Emergency Planning & Community Right-to-Know Act of 1986, and other related federal laws and regulations and state and local counterparts, as well as individual state environmental laws and regulations. Our compliance with all of these laws may be expensive and time-consuming and cause delays or limitations in our operations.

Use of Explosives

We do not directly engage in blasting services at our surface mining locations but instead use third-party contractors to perform such services. These third-party contractors are subject to numerous regulations, and, in supporting the third-party contractors in performing their blasting activities, we incur costs to design and implement blast schedules and to conduct pre-blast surveys and blast monitoring. In addition, the storage of explosives is subject to regulatory requirements.

Emerging Growth Company Status

We are an "emerging growth company," as defined in Section 2(a)(19) of the Securities Act, as modified by the Jumpstart Our Business Startups Act of 2012 (the JOBS Act). As such, we are eligible to take advantage of certain exemptions from various reporting requirements that are applicable to other public companies that are not "emerging growth companies" including, but not limited to, not being required to comply with the auditor attestation requirements of Section 404 of the Sarbanes-Oxley Act of 2002 (the Sarbanes-Oxley Act), reduced disclosure obligations regarding executive compensation in our periodic reports and proxy statements, and exemptions from the requirements of holding a non-binding advisory vote on executive compensation and shareholder approval of any golden parachute payments not previously approved.

In addition, Section 107 of the JOBS Act also provides that an "emerging growth company" can take advantage of the extended transition period provided in Section 7(a)(2)(B) of the Securities Act for complying with new or revised accounting standards, and delay compliance with new or revised accounting standards until those standards are applicable to private companies. However, we have opted out of any extended transition period, and, as a result, we will comply with new or revised accounting standards on the relevant dates on which adoption of such standards is required for non-emerging growth companies. Section 107 of the JOBS Act provides that our decision to opt out of the extended transition period for complying with new or revised accounting standards is irrevocable.

We could be an emerging growth company until the last day of the first fiscal year following the fifth anniversary of our first common equity offering, although circumstances could cause us to lose that status earlier if our annual revenues exceed $1.0 billion, if we issue more than $1.0 billion in non-convertible debt in any three-year period or if we become a "large accelerated filer" as defined in Rule 12b-2 under the Exchange Act.

Available Information

We file annual, quarterly and current reports, and amendments to those reports, and other information with the Securities and Exchange Commission (SEC). You may access and read our filings without charge through the SEC's website, at sec.gov. We also make the documents listed above available without charge through our website, *www.armstrongenergyinc.com*, as soon as practicable after we file or furnish them with the SEC. You may also request copies of the documents, at no cost, by telephone at (314) 721-8202 or by mail at Armstrong Energy, Inc., 7733 Forsyth Blvd., Suite 1625, St. Louis, Missouri, 63105 Attention: Vice President and Chief Financial Officer. The information on our website is not part of this Annual Report on Form 10-K.

Item 1A. Risk Factors

Risks Related to Our Business

We have concluded there is substantial doubt about our ability to continue as a going concern and our independent registered public accounting firm's report on our financial statements contains an explanatory paragraph describing our ability to continue as a going concern.

Our ability to continue as a going concern is an issue raised as a result of recurring losses from operations, our accumulated deficit, and the anticipation of limited liquidity to meet our obligations through March 2018. Effective November 14, 2016, we terminated our asset-based revolving credit facility entered into in December 2012 (the Revolving Credit Facility) due to restrictions in our borrowing capacity, which were anticipated to continue through the remaining term of the agreement. In addition, we entered into a settlement agreement with Thoroughbred, effective March 29, 2017, whereby we agreed, among other things, to begin paying Thoroughbred all production royalties earned on or after January 1, 2017 in cash (see Note 13,

"Related-Party Transactions," to our audited consolidated financial statements, included in Item 8 - "Financial Statements and Supplementary Data" of this Annual Report on Form 10-K). Our continuing operating losses and negative cash flow projections will limit our available liquidity for the period through March 2018. Our ability to continue as a going concern is subject to our ability to restructure our balance sheet, which could include seeking additional financing. Further, external perceptions regarding our ability to continue as a going concern and our continued net operating losses increase the difficulty of achieving such actions, and there can be no assurances that such measures will prove successful.

We have engaged financial and legal advisers to assist us in restructuring our capital structure and evaluating other potential alternatives to address the impending liquidity constraints. However, there can be no assurance that any restructuring will be possible on acceptable terms, if at all. It may be difficult to come to an agreement that is acceptable to all of our creditors. Our failure to reach an agreement on the terms of a restructuring with our creditors would have a material adverse effect on our liquidity, financial condition and results of operations. In addition, if a successful restructuring with the holders of our 11.75% Senior Secured Notes due 2019 (the Notes) is not achieved, it may be necessary for us to file a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code in order to implement a restructuring, or our creditors could force us into an involuntary bankruptcy or liquidation.

Additionally, our auditors included an explanatory paragraph to their audit opinion relating to our accompanying consolidated financial statements for the fiscal year ended December 31, 2016 regarding the substantial doubt about our ability to continue as a going concern. The financial statements have been prepared assuming that we will continue to operate as a going concern, which contemplates the realization of assets and the satisfaction of liabilities in the normal course of business.

We have a substantial amount of indebtedness, which may adversely affect our cash flow and our ability to operate our business.

At December 31, 2016, our total long-term debt was approximately $207.3 million, which is comprised of the following: $191.2 million in borrowings under the Notes and $16.1 million in other long-term debt. As of December 31, 2016, we had a long-term obligation owed to our affiliate, Thoroughbred, associated with the financing transactions in connection with the transfers of undivided interests in certain land and mineral reserves to Thoroughbred totaling $147.5 million. We also have significant lease and royalty obligations, including, but not limited to, our capital lease obligations that totaled approximately $0.6 million as of December 31, 2016, and our obligations under non-cancelable operating leases that totaled approximately $5.0 million. Future minimum advance royalties totaled approximately $4.4 million as of December 31, 2016. In addition to advance royalties, production royalties are payable based on the quantity of coal mined in future years and prospective changes to mine plans. Our ability to satisfy our debt, lease and royalty obligations, and our ability to refinance our indebtedness, will depend upon our future operating performance. The amount of indebtedness we have incurred could have significant consequences to us, such as:

- increasing our vulnerability to adverse economic, industry or competitive developments;
- requiring a substantial portion of cash flow from operations to be dedicated to the payment of principal and interest on our indebtedness, therefore reducing our ability to use our cash flow to fund our operations, capital expenditures and future business opportunities;
- making it more difficult for us to satisfy our obligations with respect to the Notes;
- limiting our ability to obtain additional financing for working capital, capital expenditures, debt service requirements, acquisitions and general corporate or other purposes; and
- limiting our flexibility in planning for, or reacting to, changes in our business or the industry in which we operate, placing us at a competitive disadvantage compared to our competitors who are less highly leveraged and who therefore may be able to take advantage of opportunities that our leverage prevents us from exploiting.

Certain of our creditors have alleged an event of default under the Notes and, if determined to be accurate, could have a material adverse effect on our business, results of operations, and financial condition.

On December 30, 2016, Rhino Resource Partners Holdings, LLC (Rhino Holdings), an entity wholly-owned by Yorktown, together with Rhino Resource Partners LP (Rhino), Royal Energy Resources, Inc. (Royal), and Rhino GP LLC (Rhino GP) entered into a put and call option agreement whereby Rhino received a call option, and Rhino Holdings received a put option, on all of the outstanding Company stock currently held by Yorktown (the Option), the majority owner of our outstanding common stock, under certain circumstances. The Option provides that Rhino can exercise the Option after 60 days

following entry of an agreement regarding the restructuring of the Notes, but in no event earlier than January 1, 2018 and no later than December 31, 2019. In exchange for Rhino Holdings granting Rhino the Option to purchase Yorktown's holdings of Armstrong Energy stock, Rhino issued 5.0 million common units to Rhino Holdings upon the execution of the Option.

In connection with entry into the Option by the aforementioned parties, on February 2, 2017, we received notice from legal counsel representing certain of the holders of the Notes (the Holders) that the Holders believe entry into the Option by the third-parties constitutes a Change of Control, as defined in the Indenture governing the Notes, and that an Event of Default occurred, as defined in the Indenture, when we failed to offer to purchase the Notes within 30 days following the purported Change of Control. However, counsel for the Holders also advised us that the Holders are not currently pursuing remedies under the Indenture related to the alleged Event of Default, but reserve their rights to do so at a future time. In addition, certain of our financing agreements include cross-default or cross-event of default provisions, which, if the aforementioned assertions were proven to be accurate, would result indirectly in an event of default under such financing arrangements.

We believe that neither a Change of Control nor an Event of Default as defined in the Indenture has occurred. To that end, we have advised legal counsel for the Holders that we dispute the allegations. However, there is no assurance the Holders or the creditors party to our other financing agreements will not pursue litigation to enforce the rights and remedies available to them under the respective financing agreements in the event of a default, which could result in substantial liabilities for the Company should such claims be upheld. If that were to occur, and we were unable to reach an amicable settlement, we may have no choice but to consider other restructuring alternatives, including seeking protection under Chapter 11 of the United States Bankruptcy Code.

Despite our substantial indebtedness level, we and our subsidiaries will still be able to incur significant additional amounts of debt, which could further exacerbate the risks associated with our substantial indebtedness.

We may be able to incur substantial additional indebtedness in the future. Although the indenture governing the Notes contains restrictions on the incurrence of additional indebtedness, these restrictions are subject to a number of significant qualifications and exceptions, and, under certain circumstances, the amount of indebtedness that could be incurred in compliance with these restrictions could be substantial. If new debt is added to our existing debt levels, the related risks that we now face would increase. In addition, the indenture governing the Notes will not prevent us from incurring obligations that do not constitute indebtedness under the indenture.

The indenture governing the Notes contains restrictions that limit our flexibility in operating our business, and breach of those covenants may cause us to be in default under the indenture. Such a default, if not cured or waived, could have a material adverse effect on our business, financial condition and results of operations, and our ability to make payments on the Notes.

The indenture governing the Notes contains various covenants that limit our ability to engage in specified types of transactions. These covenants limit our ability to, among other things:

- incur or assume liens or additional debt or provide guarantees in respect of obligations of other persons;
- pay dividends or distributions or redeem or repurchase capital stock;
- prepay, redeem or repurchase certain debt;
- make loans and investments;
- enter into agreements that restrict distributions from our subsidiaries;
- sell or transfer assets;
- enter into certain transactions with affiliates; and
- consolidate or merge with or into, or sell substantially all of our assets to, another person.

As a result of these covenants, we are limited in the manner in which we conduct our business, and we may be unable to engage in favorable business activities to finance future capital needs. A breach of any of these covenants could result in a default under the indenture. In addition, any debt agreements we enter into in the future may further limit our ability to enter into certain types of transactions. If we do not achieve the operating results required by any future agreements, we would

default under these covenants. If that occurs, our lenders, including holders of Notes, could accelerate their debt. If their debt is accelerated, we may not be able to repay all of their debt, in which case the Notes may not be fully repaid, if they are repaid at all.

Our ability to maintain adequate liquidity necessary to pay interest and principal on the Notes and service our other debt and financial obligations, and our ability to refinance all or a portion of our indebtedness or obtain additional financing, depends on many factors beyond our control.

Our ability to make scheduled payments on or to refinance our debt obligations depends on our financial condition and operating performance, which is subject to prevailing economic and competitive conditions and to certain financial, business and other factors beyond our control. We may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on the Notes or our other indebtedness. In addition, effective November 14, 2016, we terminated our Revolving Credit Facility due to restrictions in our borrowing capacity, which were anticipated to continue through the remaining term of the agreement. This has further restricted our available liquidity to meet our debt service requirements.

If our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to reduce or delay investments and capital expenditures, or to sell assets, seek additional capital or restructure or refinance the Notes or our other indebtedness. Our ability to restructure or refinance our debt will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of our debt could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business operations. The terms of the indenture governing the Notes and existing or future debt instruments may restrict us from adopting some of these alternatives. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations.

Coal prices are subject to change and a substantial or extended decline in prices could materially and adversely affect our profitability and the value of our coal reserves.

Our profitability and the value of our coal reserves depend upon the prices we receive for our coal. The contract prices we may receive in the future for coal depend upon factors beyond our control, including the following:

- the domestic and foreign supply and demand for coal;
- the demand for electricity;
- the relative cost, quantity and quality of coal available from competitors;
- competition for production of electricity from non-coal sources, which are a function of the price and availability of alternative fuels, such as natural gas, fuel oil, nuclear, hydroelectric, wind, biomass and solar power, and the location, availability, quality and price of those alternative fuel sources;
- legislative, regulatory and judicial developments, environmental regulatory changes or changes in energy policy and energy conservation measures that would adversely affect the coal industry, such as legislation limiting carbon emissions or providing for increased funding and incentives for alternative energy sources;
- domestic air emission standards for coal-fired power plants and the ability of coal-fired power plants to meet these standards by installing scrubbers and other pollution control technologies or by other means;
- adverse weather, climatic or other natural conditions, including natural disasters;
- domestic and foreign economic conditions, including economic slowdowns;
- the proximity to, capacity of and cost of, transportation, port and unloading facilities; and
- market price fluctuations for sulfur dioxide emission allowances.

A substantial or extended decline in the prices we receive for our future coal sales contracts or on the spot market could materially and adversely affect us by decreasing our profitability and the value of operating our coal reserves.

Our business requires substantial capital expenditures, and we may not have access to the capital required to reach full productive capacity at our mines.

Maintaining and expanding mines and infrastructure is capital intensive. Specifically, the exploration, permitting and development of coal reserves, mining costs, the maintenance of machinery and equipment and compliance with applicable laws and regulations require substantial capital expenditures. While a significant amount of the capital expenditures required to build-out our mines has been spent, we must continue to invest capital to maintain our production. Decisions to increase our production could also affect our capital needs. We cannot assure you that we will be able to maintain our production levels or generate sufficient cash flow, or that we will have access to sufficient financing to continue our production, exploration, permitting and development activities at or above our present levels and on our current or projected timelines, and we may be required to defer all or a portion of our capital expenditures. Our results of operations, business and financial condition, as well as our ability to satisfy our obligations under the Notes, may be materially adversely affected if we cannot make such capital expenditures.

Our coal mining operations are subject to operating risks that are beyond our control, which could result in materially increased operating expenses and decreased production levels and could materially and adversely affect our profitability.

We mine coal both at underground and at surface mining operations. Certain factors beyond our control, including those listed below, could disrupt our coal mining operations, adversely affect production and shipments and increase our operating costs:

- poor mining conditions resulting from geological, hydrologic or other conditions that may cause instability of mining portals, highwalls or spoil piles or cause damage to mining equipment, nearby infrastructure or mine personnel;
- delays or challenges to and difficulties in obtaining or renewing permits necessary to produce coal or operate mining or related processing and loading facilities;
- adverse weather and natural disasters, such as heavy rains or snow, flooding and other natural events affecting operations, transportation or customers;
- a major incident at the mine site that causes all or part of the operations of the mine to cease for some period of time;
- mining, processing and plant equipment failures and unexpected maintenance problems;
- unexpected or accidental surface subsidence from underground mining; and
- accidental mine water discharges, fires, explosions or similar mining accidents.

If any of these conditions or events occurs, we could experience a delay or halt of production or shipments or our operating costs could increase significantly.

Competition within the coal industry could put downward pressure on coal prices, and, as a result, materially and adversely affect our revenues and profitability.

We compete with numerous other coal producers in the Illinois Basin and in other coal producing regions of the United States, primarily Central Appalachia and the Powder River Basin. The most important factors on which we compete are:

- delivered price (i.e., the cost of coal delivered to the customer on a cents per million Btu basis, including transportation costs, which are generally paid by our customers either directly or indirectly);
- coal quality characteristics (primarily heat, sulfur, ash and moisture content); and
- reliability of supply.

Our competitors may have, among other things, greater liquidity, greater access to credit and other financial resources, newer or more efficient equipment, lower cost structures, partnerships with transportation companies or more effective risk

management policies and procedures. Our failure to compete successfully could have a material adverse effect on our business, financial condition or results of operations.

International demand for U.S. coal also affects competition within our industry. The demand for U.S. coal exports depends upon a number of factors outside our control, including the overall demand for electricity in foreign markets, currency exchange rates, ocean freight rates, port and shipping capacity, the demand for foreign-priced steel, both in foreign markets and in the U.S. market, general economic conditions in foreign countries, technological developments and environmental and other governmental regulations in both U.S. and foreign markets. If foreign demand for U.S. coal were to further decline, this could cause increased competition among coal producers for the sale of coal in the United States to intensify, potentially resulting in significant downward pressure on domestic coal prices.

Decreases in demand for electricity and changes in coal consumption patterns of U.S. electric power generators could adversely affect coal prices and materially and adversely affect our results of operations.

Our coal is used primarily as fuel for electricity generation. Overall economic activity and the associated demand for power by industrial users can have significant effects on overall electricity demand. An economic slowdown can significantly slow the growth of electrical demand and could result in contraction of demand for coal. Declines in international prices for coal generally will affect U.S. prices for coal.

Our business is closely linked to domestic demand for electricity, and any changes in coal consumption by U.S. electric power generators would likely affect our business over the long term. In 2016, we sold a substantial majority of our coal to domestic electric power generators, and we have multi-year coal supply agreements in place with electric power generators for a portion of our future production. The amount of coal consumed by electric power generation is affected by, among other things:

- general economic conditions, particularly those affecting industrial electric power demand, such as the downturn in the U.S. economy and financial markets in 2008 and 2009;
- environmental and other governmental regulations, including those impacting coal-fired power plants;
- energy conservation efforts and related governmental policies; and
- indirect competition from alternative fuel sources for power generation, such as natural gas, fuel oil, nuclear, hydroelectric, wind, biomass and solar power, and the location, availability, quality and price of those alternative fuel sources, and government subsidies for those alternative fuel sources.

Decreases in the demand for electricity could take place in the future, such as decreases that could be caused by a worsening of current economic conditions, a prolonged economic recession or other similar events, and could have a material adverse effect on the demand for coal and on our business over the long term.

Changes in the coal industry that affect our customers, such as those caused by decreased electricity demand and increased competition, could also adversely affect our business. Indirect competition from gas-fired plants that are cheaper to construct and easier to permit has the most potential to displace a significant amount of coal-fired generation in the near term, particularly older, less efficient coal-powered generators. In addition, uncertainty caused by federal and state regulations could cause coal customers to be uncertain of their coal requirements in future years, which could adversely affect our ability to sell coal to our customers under multi-year coal supply agreements.

Weather patterns can also greatly affect electricity demand. Extreme temperatures, both hot and cold, cause increased power usage and, therefore, increased generating requirements from all sources. Mild temperatures, on the other hand, result in lower electrical demand. Any downward pressure on coal prices, due to decreases in overall demand or otherwise, including changes in weather patterns, would materially and adversely affect our results of operations.

The use of alternative energy sources for power generation could reduce coal consumption by U.S. electric power generators, which could result in lower prices for our coal.

In 2016, a substantial majority of the tons we sold were to domestic electric power generators. The amount of coal consumed for U.S. electric power generation is affected by, among other things:

- the location, availability, quality and price of alternative energy sources for power generation, such as natural gas, fuel oil, nuclear, hydroelectric, wind, biomass and solar power; and

- technological developments, including those related to alternative energy sources.

Gas-fired electricity generation has the potential to displace coal-fired generation, particularly from older, less efficient coal-powered generators. We expect that many of the new power plants needed to meet increasing demand for electricity generation may be fueled by natural gas because gas-fired plants are cheaper to construct and permits to construct these plants are easier to obtain as natural gas-fired plants are seen as having a lower environmental impact than coal-fired plants. Current developments in natural gas production processes have lowered the cost and increased the supply, resulting in greater use of natural gas for electricity generation. While the U.S. Energy Information Administration (the EIA) projects that electricity generation will grow at an annual average rate of 0.7% through 2040, it projects that the percentage of electricity generated from coal will decrease to approximately 19% of total generation by 2040, compared with 30% during 2016. According to the EIA, total coal consumption in the U.S. in 2016 decreased by approximately 67 million tons, or 8.3%, from 2015 levels.

In addition, state and federal mandates for increased use of electricity from renewable energy sources could have an adverse impact on the market for our coal. Many states have mandates requiring electricity suppliers to use renewable energy sources to generate a certain percentage of power. There have been numerous proposals to establish a similar uniform, national energy portfolio standard in the U.S., although none of these proposals have been enacted to date. Possible advances in technologies and incentives, such as tax credits, to enhance the economics of renewable energy sources could make these sources more competitive with coal. Any reduction in the amount of coal consumed by domestic electric power generators could reduce the price of coal that we mine and sell, thereby reducing our revenues and materially and adversely affecting our business and results of operations.

Inaccuracies in our estimates of our coal reserves could result in decreased profitability from lower than expected revenues or higher than expected costs.

Our future performance depends on, among other things, the accuracy of our estimates of our proven and probable coal reserves. The estimates of our reserves are based on engineering, economic and geological data assembled, analyzed and reviewed by internal and third-party engineers and consultants. We update our estimates of the quantity and quality of proven and probable coal reserves periodically to reflect the production of coal from the reserves, updated geological models and mining recovery data, the tonnage contained in new areas acquired and estimated costs of production and sales prices. There are numerous factors and assumptions inherent in estimating the quantities and qualities of, and costs to mine, coal reserves, including many factors beyond our control, including the following:

- quality of the coal;

- geological and mining conditions, which may not be fully identified by available exploration data and/or may differ from our experiences in areas where we currently mine;

- the percentage of coal ultimately recoverable;

- the assumed effects of regulation, including the issuance of required permits, taxes, including severance and excise taxes and royalties, and other payments to governmental agencies;

- assumptions concerning the timing for the development of the reserves; and

- assumptions concerning equipment and productivity, future coal prices, operating costs, including for critical supplies such as fuel, tires and explosives, capital expenditures and development and reclamation costs, including the cost of reclamation bonds.

As a result, estimates of the quantities and qualities of economically recoverable coal attributable to any particular group of properties, classifications of reserves based on risk of recovery, estimated cost of production, and estimates of future net cash flows expected from these properties as prepared by different engineers, or by the same engineers at different times, may vary materially due to changes in the above factors and assumptions. Actual production recovered from identified reserve areas and properties, and revenues and expenditures associated with our mining operations, may vary materially from estimates. Any inaccuracy in our estimates related to our reserves could result in decreased profitability from lower than expected revenues and/or higher than expected costs.

Increases in the costs of mining and other industrial supplies, including steel-based supplies, diesel fuel, rubber tires and explosives, or the inability to obtain a sufficient quantity of those supplies, may adversely affect our operating costs or disrupt or delay our production.

Our coal mining operations use significant amounts of steel, electricity, diesel fuel, explosives, rubber tires and other mining and industrial supplies. The cost of roof bolts we use in our underground mining operations depends on the price of scrap steel. We also use significant amounts of diesel fuel and tires for the trucks and other heavy machinery we use. If the prices of mining and other industrial supplies, particularly steel-based supplies, diesel fuel and rubber tires, increase, our operating costs may be adversely affected. In addition, if we are unable to procure these supplies, our coal mining operations may be disrupted or we could experience a delay or halt in our production.

A defect in title or the loss of a leasehold interest in certain property could limit our ability to mine our coal reserves or result in significant unanticipated costs.

We conduct part of our coal mining operations on properties that we lease. A title defect or the loss of a lease could adversely affect our ability to mine the associated coal reserves. We may not verify title to our leased properties or associated coal reserves until we have committed to developing those properties or coal reserves. We may not commit to develop property or coal reserves until we have obtained necessary permits. As such, the title to property that we intend to lease or coal reserves that we intend to mine may contain defects prohibiting our ability to conduct mining operations. Similarly, our leasehold interests may be subject to superior property rights of other third parties or to royalties owed to those third parties. In order to conduct our mining operations on properties where these defects exist, we may incur unanticipated costs. In addition, some leases require us to produce a minimum quantity of coal and require us to pay minimum production royalties. Our inability to satisfy those requirements may cause the leasehold interest to terminate.

We outsource certain aspects of our business to third-party contractors, which subjects us to risks, including disruptions in our business.

We contract with third parties to provide blasting services at all of our mines and loading services at our barge loadout facility located on the Green River. In addition, we contract with third parties to provide truck transportation services between our mines and our preparation plants. Accordingly, we are subject to the risks associated with the contractors' ability to successfully provide the necessary services to meet our needs. If the contractors are unable to adequately provide the contracted services, and we are unable to find alternative service providers in a timely manner, our ability to conduct our coal mining operations and deliver coal to our customers may be disrupted.

The availability and reliability of transportation facilities and fluctuations in transportation costs could affect the demand for our coal or impair our ability to supply coal to our customers.

We depend upon barge, rail and truck transportation systems to deliver coal to our customers. Disruptions in transportation services due to weather-related problems, mechanical difficulties, strikes, lockouts, bottlenecks, and other events could impair our ability to supply coal to our customers. In addition, increases in transportation costs, including the price of gasoline and diesel fuel, could make coal a less competitive source of energy when compared to alternative fuels or could make coal produced in one region of the United States less competitive than coal produced in other regions of the United States or abroad. If transportation of our coal is disrupted or if transportation costs increase significantly and we are unable to find alternative transportation providers, our coal mining operations may be disrupted, we could experience a delay or halt of production or our profitability could decrease significantly.

Our profitability depends in part upon the multi-year coal supply agreements we have with our customers. Changes in purchasing patterns in the coal industry could make it difficult for us to extend our existing multi-year coal supply agreements or to enter into new agreements in the future.

We sell a majority of our coal under multi-year coal supply agreements. Under these arrangements, we fix the prices of coal shipped during the initial year and may adjust the prices in later years. As a result, at any given time the market prices for similar-quality coal may exceed the prices for coal shipped under these arrangements. Changes in the coal industry may cause some of our customers not to renew, extend or enter into new multi-year coal supply agreements with us or to enter into agreements to purchase fewer tons of coal than in the past or on different terms or prices. In addition, uncertainty caused by federal and state regulations, including the Clean Air Act, could deter our customers from entering into multi-year coal supply agreements.

Because we sell a majority of our coal production under multi-year coal supply agreements, our ability to capitalize on more favorable market prices may be limited. Conversely, at any given time we are subject to fluctuations in market prices for the quantities of coal that we are planning to produce but which we have not committed to sell. As described above under "Coal prices are subject to change and a substantial or extended decline in prices could materially and adversely affect our profitability and the value of our coal reserves," the market prices for coal may be volatile and may depend upon factors beyond our control. Our profitability may be adversely affected if we are unable to sell uncommitted production at favorable prices or at all. For more information about our multi-year coal supply agreements, see Item 1 – "Business — Customers — Multi-Year Coal Supply Agreements."

Our multi-year coal supply agreements subject us to renewal risks.

We sell most of the coal we produce under multi-year coal supply agreements. To the extent we are not successful in renewing, extending or renegotiating our multi-year coal supply agreements on favorable terms, we may have to accept lower prices for the coal we sell or sell reduced quantities of coal in order to secure new sales contracts for our coal.

Prices and quantities under our multi-year coal supply agreements are generally based on expectations of future coal prices at the time the contract is entered into, renewed, extended or reopened. The expectation of future prices for coal depends upon factors beyond our control, including the following:

- domestic and foreign supply and demand for coal;
- domestic demand for electricity, which tends to follow changes in general economic activity;
- domestic and foreign economic conditions;
- the price, quantity and quality of other coal available to our customers;
- competition for production of electricity from non-coal sources, including the price and availability of alternative fuels and other sources, such as natural gas, fuel oil, nuclear, hydroelectric, wind biomass and solar power, and the effects of technological developments related to these non-coal energy sources;
- domestic air emission standards for coal-fired power plants, and the ability of coal-fired power plants to meet these standards by installing scrubbers and other pollution control technologies, purchasing emissions allowances or other means;
- legislative and judicial developments, regulatory changes, or changes in energy policy and energy conservation measures that would adversely affect the coal industry; and
- the decision by one or more of our key customers to close certain of its facilities.

For more information regarding our major customers and multi-year coal supply agreements, see Item 1 – "Business — Customers."

The loss of, or significant reduction in purchases by, our largest customers could adversely affect our profitability.

For the year ended December 31, 2016, we derived approximately 85% of our total coal revenues from sales to our two largest customers. We have several multi-year coal supply agreements with each of these customers, with various expiration dates extending through 2020. However, several of our multi-year coal supply agreements contain reopener provisions pursuant to which either party can request reopening of the agreement to renegotiate price and other terms for the remaining term of such agreement, and, subsequent to any such reopening, the failure to reach an agreement can lead to the termination of such agreement. In addition, one of our multi-year coal supply agreements provides that the customer has the unilateral right to terminate the agreement upon 60 days' written notice, in which case the customer is required to pay us a termination fee equal to 10% of the base price multiplied by the remaining number of tons to be delivered under the agreement. If our multi-year coal supply agreements with these two customers are terminated early pursuant to the reopener provisions, or we fail to extend or renew our multi-year coal supply agreements with these two customers, or if the agreements are terminated as a result of not being assigned following a change in control, our business and results of operations could be materially and adversely affected. Even if we are able to extend or renew our multi-year coal supply agreements with these two customers, if market prices for such coal agreements are low at the time of such extensions or renewals or increases in costs during the term of such extended

or renewed agreements are greater than the offsets from our cost pass-through and inflation adjustment provisions under such extended or renewed agreements, our business and results of operations could be materially and adversely affected.

Our multi-year coal supply agreements typically contain force-majeure provisions allowing the parties to temporarily suspend performance during specified events beyond their control. Most of our multi-year coal supply agreements also contain provisions requiring us to deliver coal that satisfies certain quality specifications, such as heat value, sulfur content, ash content, chlorine content, hardness and ash fusion temperature. These provisions in our multi-year coal supply agreements could result in negative economic consequences to us, including price adjustments, purchasing replacement coal in a higher-priced open market, the rejection of deliveries or, in the extreme, contract termination. Our profitability may be negatively affected if we are unable to seek protection during adverse economic conditions or if we incur financial or other economic penalties as a result of the provisions of our multi-year coal supply agreements.

Negotiations to extend existing agreements or enter into new multi-year coal supply agreements with our largest customers, as well as other existing customers, may not be successful, and those customers may not continue to purchase coal from us under multi-year coal supply agreements or may significantly reduce their purchases of coal from us. In addition, interruption in the purchases by or operations of our principal customers could significantly affect our results of operations and cash flows from operations, if we are unable to timely replace such demand.

The current challenging economic environment, along with difficult and volatile conditions in the capital and credit markets, could materially adversely affect our financial position, results of operations or cash flows, and we are unsure whether these conditions will improve in the near future.

The United States economy and global credit markets remain volatile. Worsening economic conditions or factors that negatively affect the economic health of the United States could reduce our revenues and thus adversely affect our results of operations. The domestic markets have historically experienced disruptions, including, among other things, volatility in security prices, diminished liquidity and credit availability, rating downgrades of certain investments and declining valuations of others, failure and potential failures of major financial institutions, unprecedented government support of financial institutions, high unemployment rates and increasing interest rates. Furthermore, if these developments continue or worsen it may adversely affect the ability of our customers and suppliers to obtain financing to perform their obligations to us. We believe that further deterioration or a prolonged period of economic weakness will have an adverse impact on our results of operations, business and financial condition, as well as our ability to satisfy our obligations under the Notes.

We may not recover our investments in our mining and other related assets, which may require us to recognize non-cash impairment charges related to those assets.

The value of our assets may be adversely affected by numerous uncertain factors, some of which are beyond our control, including:

- unfavorable changes in the economic environments in which we operate;
- lower-than-expected demand and coal pricing;
- unfavorable regulatory or legal developments impacting our industry;
- technical and geological operating difficulties;
- an inability to economically extract our coal reserves; and
- unanticipated increases in operating costs.

These may cause us to fail to recover all or a portion of our investments in those assets and may trigger the recognition of non-cash impairment charges in the future, which could have a substantial adverse impact on our results of operations.

As described in Note 4, "Asset Impairment and Restructuring Charges" to our audited consolidated financial statements, included in Item 8 - "Financial Statements and Supplementary Data" of this Annual Report on Form 10-K, we recognized asset impairment charges of $4.4 million and $137.7 million in 2016 and 2015, respectively. Because of the volatile nature of U.S. coal markets, it is reasonably possible that our current estimates of projected future cash flows from our mining assets may change in the near term, which may result in the need for further adjustments to the carrying value of mineral rights and other mining assets.

Our assets and operations are concentrated in Western Kentucky and the Illinois Basin, and a disruption within that geographic region could adversely affect the Company's performance.

We rely exclusively on sales generated from products distributed from the Illinois Basin and Western Kentucky. Due to our lack of diversification in geographic location, an adverse development in these areas, including adverse developments due to catastrophic events or weather and decreases in demand for coal or electricity, could have a significantly greater adverse impact on our ability to operate our business and our results of operations than if we held more diverse assets and locations.

We have been removed as the general partner of Thoroughbred by Yorktown without our consent.

Effective September 1, 2016, Yorktown exercised its right under the Second Amended and Restated Agreement of Limited Partnership of Thoroughbred Resources L.P. to remove our subsidiary, Elk Creek GP, LLC, as general partner of Thoroughbred without our consent. As a result of the change in control of Thoroughbred, our ability to enter into, or obtain renewals of, coal lease or mining license agreements with Thoroughbred could be adversely affected. We may have to seek alternative agreements or arrangements with unrelated parties, and such alternative agreements or arrangements may not be available or may be on less favorable terms.

Our independent registered public accounting firm will not be required to attest to the effectiveness of our internal control over financial reporting pursuant to Section 404 of the Sarbanes Oxley Act of 2002 (Section 404) for so long as we are an emerging growth company.

We are required to disclose changes made in our internal control over financial reporting on a quarterly basis, and we are required to assess the effectiveness of our internal controls annually. However, for as long as we are an "emerging growth company," our independent registered public accounting firm will not be required to attest to the effectiveness of our internal control over financial reporting pursuant to Section 404. We could be an emerging growth company until the last day of the first fiscal year following the fifth anniversary of our first common equity offering, although circumstances could cause us to lose that status earlier if our annual revenues exceed $1.0 billion, if we issue more than $1.0 billion in non-convertible debt in any three-year period or if we become a "large accelerated filer" as defined in Rule 12b-2 under the Exchange Act. Even if we conclude that our internal control over financial reporting is effective, our independent registered public accounting firm may still decline to attest to our assessment or may issue a report that is qualified if it is not satisfied with our internal controls or the level at which our internal controls are documented, designed, operated or reviewed, or if it interprets the relevant requirements differently from us.

Failure to obtain or renew surety bonds on acceptable terms could affect our ability to secure reclamation and coal lease obligations and, therefore, our ability to mine or lease coal.

Federal and state laws require us to obtain surety bonds to secure performance or payment of certain long-term obligations, such as mine closure or reclamation costs, federal and state workers' compensation costs, coal leases and other obligations. In light of our current financial condition and substantial doubt about our ability to continue as a going concern, we may have difficulty procuring or maintaining our surety bonds. Our bond issuers may demand higher fees, additional collateral, including letters of credit or other terms less favorable to us upon those renewals. Because we are required by state and federal law to have these bonds in place before mining can commence or continue, failure to maintain surety bonds, letters of credit or other guarantees or security arrangements would materially and adversely affect our ability to mine or lease coal. That failure could result from a variety of factors, including lack of availability, higher expense or unfavorable market terms, the exercise by third-party surety bond issuers of their right to refuse to renew the surety and restrictions on availability of collateral for current and future third-party surety bond issuers under the terms of our financing arrangements.

Our ability to operate our business effectively could be impaired if we fail to attract and retain key management personnel.

Our ability to operate our business and implement our strategies depends on the continued contributions of our executive officers and key employees. In particular, we depend significantly on our senior management's long-standing relationships within our industry. The loss of any of our senior executives could have a material adverse effect on our business. In addition, we believe that our future success will depend on our continued ability to attract and retain highly skilled management personnel with coal industry experience, and competition for these persons in the coal industry is intense. We may not be able to continue to employ key personnel or attract and retain qualified personnel in the future, and our failure to retain or attract key personnel could have a material adverse effect on our ability to effectively operate our business.

We are subject to various legal proceedings, which may have an adverse effect on our business.

We are involved in a number of threatened and pending legal proceedings incidental to our normal business activities. While we cannot predict the outcome of the proceedings, there is always the potential that the costs of litigation in an individual matter or the aggregation of many matters could have an adverse effect on our cash flows, results of operations or financial position.

A shortage of skilled labor in the mining industry could reduce labor productivity and increase costs, which could have a material adverse effect on our business and results of operations.

Efficient coal mining using modern techniques and equipment requires skilled laborers in multiple disciplines, such as equipment operators, mechanics, electricians and engineers, among others. We have from time to time encountered shortages for these types of skilled labor. If we experience shortages of skilled labor in the future, our labor and overall productivity or costs could be materially and adversely affected. If our labor prices increase, or if we experience materially increased health and benefit costs with respect to our employees, our results of operations could be materially and adversely affected.

Our work force could become unionized in the future, which could adversely affect the stability of our production and materially reduce our profitability.

All of our mines are operated by non-union employees. Our employees have the right at any time under the National Labor Relations Act to form or affiliate with a union, subject to certain voting and other procedural requirements. If our employees choose to form or affiliate with a union and the terms of a union collective bargaining agreement are significantly different from our current compensation and job assignment arrangements with our employees, these arrangements could adversely affect the stability of our production through potential strikes, slowdowns, picketing and work stoppages, and materially reduce our profitability.

Our ability to collect payments from our customers could be impaired if their creditworthiness deteriorates.

Our ability to receive payment for the coal we sell depends on the continued creditworthiness of our customers. The current economic volatility and tightening credit markets increase the risk that we may not be able to collect payments from our customers. A continuation or worsening of current economic conditions or other prolonged global or U.S. recessions could also affect the creditworthiness of our customers. If the creditworthiness of a customer declines, this would increase the risk that we may not be able to collect payment for all of the coal we sell to that customer. If we determine that a customer is not creditworthy, we may not be required to deliver coal under the customer's coal sales contract. If we are able to withhold shipments, we may decide to sell the customer's coal on the spot market, which may be at prices lower than the contract price, or we may be unable to sell the coal at all. Furthermore, the bankruptcy of any of our customers could have a material adverse effect on our financial position. In addition, competition with other coal suppliers could force us to extend credit to customers on terms that could increase the risk of payment default.

Our consolidated balance sheets include interests in coal reserves for which legal title has been transferred to Thoroughbred.

As described in Note 13, "Related-Party Transactions," to our audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K, we have sold certain of our coal reserves to Thoroughbred. Under U.S. generally accepted accounting principles (GAAP), these transfers are treated as financing transactions, with one consequence thereof being that the entire book value of these reserves is carried on our consolidated balance sheets, notwithstanding the fact that legal title to the reserves has been transferred to Thoroughbred. As a result, the collateral agent's ability to foreclose on and liquidate our assets comprising coal reserves that are the subject of these lease transactions will be limited to the portion of the reserves owned by us. As of December 31, 2016, approximately 25% of the net book value of our "property, plant, equipment, and mine development, net" reflected assets for which legal title has been transferred to Thoroughbred.

Risks Related to Environmental and Other Regulations and Legislation

Extensive environmental regulations, including existing and potential future regulatory requirements relating to air emissions, affect our customers and could reduce the demand for coal as a fuel source, causing coal prices and sales of our coal to materially decline.

The operations of coal consumers, such as the utility industry, are subject to extensive regulation regarding the environmental impact of their activities, particularly with respect to air emissions, which could affect demand for our coal. For example, the CAA and similar state and local laws extensively regulate the amount of SO2, particulate matter, NOx, mercury, and other compounds emitted into the air from electric power plants, which are the largest end-users of our coal. A series of more stringent requirements relating to particulate matter, ozone, haze, mercury, SO2, NOx and other air pollutants will, or are expected to, become effective in coming years. In addition, concerted conservation efforts that result in reduced electricity consumption could cause coal prices and sales of our coal to materially decline.

More stringent air emissions limitations may require significant emissions control expenditures for many coal-fired power plants and could have the effect of making coal-fired plants less profitable. As a result, some power plants may continue to switch to other fuels that generate less of these emissions or they may close. Any switching of fuel sources away from coal, closure of existing coal-fired plants, or reduced construction of new plants could have a material adverse effect on demand for and prices received for our coal.

It is possible that new environmental legislation or regulations may be adopted, or that existing laws or regulations may be differently interpreted or more stringently enforced, any of which could have a significant impact on our mining operations or our customers' ability to use coal.

Recent developments in the regulation of GHG emissions and coal ash could materially adversely affect our customers' demand for coal and our results of operations, cash flows and financial condition.

One major by-product of burning coal is the emission of CO2 into the atmosphere. In 2009, the EPA published the Endangerment Finding asserting that emissions of CO2 and other GHGs present an endangerment to public health and the environment, and the EPA has begun to regulate GHG emissions pursuant to the CAA. The EPA has finalized a rule to regulate GHG emissions from new power plants. The finalized standard requires CCS, a technology that is not yet commercially feasible without government subsidies and that has not been demonstrated in the marketplace. This requirement effectively prevents construction of new coal fired power plants. In August 2015, the EPA finalized GHG emissions regulations for modified and existing power plants. The rule for modified sources requires reducing GHG emissions from any modified or reconstructed source and could limit the ability of generators to upgrade coal-fired power plants, thereby reducing the demand for coal. The rule for existing sources proposes to establish different target emission rates for each state and has an overall goal to achieve a 32% reduction of CO2 emissions from 2005 levels by 2030. If upheld by courts, the regulation could lead to premature retirements of coal-fired electric generating units and significantly reduce the demand for coal.

In addition, many states and regions have adopted GHG initiatives, and there have been numerous protests of, and challenges to, the permitting of new coal-fired power plants by environmental organizations and state regulators due to concerns related to GHG emissions. Further, governmental agencies have been providing grants or other financial incentives to entities developing or selling alternative energy sources with lower levels of GHG emissions, which may lead to more competition from those entities. There have also been several public nuisance lawsuits brought against power, coal, oil and gas companies alleging that their operations are contributing to climate change. The plaintiffs are seeking various remedies, including punitive and compensatory damages and injunctive relief. While the U.S. Supreme Court recently determined that such claims cannot be pursued under federal law, plaintiffs may seek to proceed under state common law.

The enactment of these and other laws or regulations regarding emissions from the combustion of coal or other actions to limit such emissions, such as those discussed in Item 1-"Business-Regulation and Laws," could result in electricity generators switching from coal to other fuel sources thereby reducing demand for our coal. The potential impact on us of future laws, regulations or other policies or circumstances will depend upon the degree to which any such laws, regulations or other policies or circumstances force electricity generators to diminish their reliance on coal as a fuel source. Such impacts could have a material adverse effect on our results of operations, cash flows and financial condition, as well as on our ability to meet our debt obligations.

Numerous political and regulatory authorities and governmental bodies, as well as environmental activist groups, are devoting substantial resources to anti-coal activities to minimize or eliminate the use of coal as a source of electricity generation, thereby further reducing the demand and pricing for coal and potentially materially and adversely impacting our future financial results, liquidity and growth prospects.

Concerns about the environmental and perceived global climate impacts of coal combustion are resulting in increased regulation of coal combustion, unfavorable lending policies by lending institutions and divestment efforts affecting the investment community, which could significantly affect demand for our products or our securities and our ability to obtain financing.

Global climate issues continue to attract significant public and scientific attention. Some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. Numerous reports, such as the the Fourth and Fifth Assessment Reports of the Intergovernmental Panel on Climate Change have expressed concern about the impacts of human activity, especially from fossil fuel combustion, on global climate issues. As a result, increasing government attention is being paid to global climate issues and to emissions of GHGs, including emissions of carbon dioxide from coal combustion by power plants.

Federal, state and local governments may pass laws mandating the use of alternative energy sources, such as wind power and solar energy, which may decrease demand for our coal products. The CPP is one of a number of recent developments aimed at limiting GHG emissions, which would adversely affect our ability to sell coal. Future regulation of GHG emissions in the U.S. could occur pursuant to future U.S. treaty obligations, statutory or regulatory changes at the federal, state or local level, or otherwise. In addition, Congress has extended certain tax credits for renewable sources of electric generation, which will increase the ability of these sources to compete with our coal products in the market. These actions could result in electricity generators further switching from coal to other fuel sources or additional coal-fueled power plant closures. See Item 1-"Business-Regulation and Laws."

There have also been efforts in recent years affecting the investment community, including investment advisors, sovereign wealth funds, public pension funds, universities and other groups, promoting the divestment of fossil fuel equities and also pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. In California, for example, legislation was signed into law in October 2015 that requires California's state pension funds to divest investments in companies that generate 50% or more of their revenue from coal mining by July 2017. Other activist campaigns have urged banks to cease financing coal-driven businesses. As a result, several major banks have enacted such policies. The impact of such efforts may adversely affect the demand for and price of securities issued by us, and impact our access to the capital and financial markets.

In addition, several well-funded non-governmental organizations have explicitly undertaken campaigns to minimize or eliminate the use of coal as a source of electricity generation. Collectively, these actions and campaigns could adversely impact our future financial results, liquidity and growth prospects.

Legal requirements that we expect to significantly expand scrubbed coal-fired electricity generating capacity may be overturned or not enacted at all, which could result in less demand for Illinois Basin coal than we anticipate and materially and adversely affect our coal prices and/or sales.

Although a number of legal requirements have been or are in the process of being implemented that are expected to expand significantly the scrubbed coal-fired electricity generating capacity in the U.S., regulations driving this trend are subject to legal challenge and could also be the subject of future legislation that withdraws any authorization for such requirements. For example, recently, new regulations have been implemented, affirmed or proposed that have resulted in the retirement of coal-fired generators and have the potential to result in additional premature retirements. See Item 1 - "Business-Regulation and Laws." These regulations and any similar future regulatory developments could result in significantly less expansion of scrubbed coal-fired electricity generating capacity than we anticipate. This in turn could mean that the strong increase in demand for relatively high-sulfur Illinois Basin coal we believe will occur in the future may not materialize or may not materialize as soon as it otherwise would. This could adversely affect the demand and prices received for our coal.

Our failure to obtain and renew permits and approvals necessary for our mining operations could negatively affect our business.

Coal production is dependent on our ability to obtain and maintain various federal and state permits and approvals to mine our coal reserves within the timeline specified in our mining plans. The permitting rules, and the interpretations of these rules, are complex, change frequently and are often subject to discretionary interpretations by regulators, which may increase our costs or possibly preclude the continuance of ongoing mining operations or the development of future mining operations. In addition, the public, including non-governmental organizations, anti-mining groups and individuals, have certain statutory
rights to comment upon and otherwise affect the permitting process, including court intervention. The slowing pace at which necessary permits are issued or renewed for new and existing mines has materially affected coal production, especially in Central Appalachia. Permitting by the Corps, the EPA and the Department of the Interior has become subject to "enhanced review" in recent years under both SMCRA and the CWA, and may become subject to new and expanded CWA, SMCRA and state counterpart regulation in the near future.

Typically, we submit the necessary permit applications 12 to 30 months before we plan to mine a new area. Some of

our required mining permits are becoming increasingly difficult to obtain within the timeframes to which we were previously accustomed, and in some instances, we have had to delay the mining of coal in certain areas covered by the application in order to obtain required permits and approvals. Permits could be delayed or become difficult to obtain in the future if the EPA continues its enhanced review of CWA permit applications, if the CWR becomes effective and is implemented, if OSM's SPR is enacted as a final rule, or other federal or state rule or policy changes, such as changes to water quality standards occur. If the required permits are not issued or renewed in a timely fashion or at all, or if permits issued or renewed are conditioned in a manner that restricts our ability to efficiently and economically conduct our mining activities, we could suffer a material reduction in our production and our operations, and there could be a material adverse effect on our ability to produce coal profitably. See Item 1 - "Business-Regulation and Laws."

Federal or state regulatory agencies have the authority to order certain of our mines to be temporarily or permanently closed under certain circumstances, which could materially and adversely affect our ability to meet our customers' demands.

Federal or state regulatory agencies, including MSHA, have the authority under certain circumstances following significant health and safety incidents, such as fatalities, to order a mine to be temporarily or permanently closed. If this were to occur, capital expenditures could be required in order for us to be allowed to reopen the mine. In the event that these agencies order the closing of our mines, certain of our coal sales contracts allow us to issue force majeure notices which suspend our obligations to deliver coal under these contracts. However, our customers may challenge our issuances of force majeure notices. If these challenges are successful, we may have to purchase coal from third-party sources, if it is available, to fulfill these obligations, incur capital expenditures to reopen the mines and/or negotiate settlements with the customers, which may result in price reductions, the reduction of commitments or the extension of time for delivery under the contracts or terminate the customers' contracts at issue. Any of these actions could have a material adverse effect on our business and results of operations.

Extensive environmental laws and regulations impose significant costs on our mining operations, and future laws and regulations could materially increase those costs or limit our ability to produce and sell coal.

The coal mining industry is subject to increasingly strict regulation by federal, state and local authorities with respect to environmental matters such as:

- limitations on land use;
- mine permitting and licensing requirements;
- reclamation and restoration of mining properties after mining is completed;
- management and disposal of materials generated by mining operations;
- storage, treatment and disposal of wastes;
- remediation of contaminated soil and water, including wetlands and groundwater;
- air quality standards;
- water pollution, including numeric and narrative water quality standards;
- protection of human health,
- plant-life and wildlife, including endangered or threatened species;
- protection of wetlands;
- discharge of materials into the environment;
- effects of mining on surface water and groundwater quality and availability; and
- management of electrical equipment containing polychlorinated biphenyls.

The costs, liabilities and requirements associated with the laws and regulations related to these and other environmental matters may be costly and time-consuming and may delay commencement or continuation of exploration or production operations. We cannot assure you that we have been or will be at all times in compliance with the applicable laws and regulations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of cleanup and site restoration costs and liens, the issuance of injunctions to limit or cease operations, the suspension or revocation of permits and other enforcement measures that could have the effect of limiting production from our operations. We may incur material costs and liabilities resulting from claims for damages to property or injury to persons arising from our operations. If we are pursued for sanctions in respect of these matters, we could be materially and adversely affected.

New legislation or administrative regulations or new interpretations or enforcement of existing laws and regulations may also require us to change operations significantly or incur increased costs. Such changes could have a material adverse effect on our financial condition and results of operations. See Item 1 - "Business-Regulation and Laws."

If the assumptions underlying our estimates of reclamation and mine closure obligations are inaccurate, our costs could be greater than anticipated.

SMCRA and counterpart state laws and regulations establish operational, reclamation and closure standards for all aspects of surface mining, as well as most aspects of underground mining. We base our estimates of reclamation and mine closure liabilities on permit requirements, engineering studies and our engineering expertise related to these requirements. Our management and engineers periodically review these estimates. The estimates can change significantly if actual costs vary from our original assumptions or if governmental regulations change significantly. We are required to record new obligations as liabilities at fair value under generally accepted accounting principles. In estimating fair value, we consider the estimated current costs of reclamation and mine closure and apply inflation rates and third-party profit, as required. The third-party profit is an estimate of the approximate markup that would be charged by contractors for reclamation work performed on our behalf. The resulting estimated reclamation and mine closure obligations could change significantly if actual amounts change significantly from our assumptions, which could have a material adverse effect on our results of operations and financial condition.

Our operations may affect the environment or cause exposure to hazardous substances, and our properties may have environmental contamination, which could result in material liabilities to us.

Our operations currently use hazardous materials and generate limited quantities of hazardous wastes from time to time, which may affect runoff or drainage water or other aspects of the environment. We could become subject to claims for toxic torts, natural resource damages and other damages as well as for the investigation and cleanup of soil, surface water, groundwater and other media. Such claims may arise out of conditions at sites that we currently own or operate, as well as at sites that we previously owned or operated or may acquire. Our liability for such claims may be joint and several so that we may be held responsible for more than our share of the contamination or other damages or even for the entire amount.

We maintain extensive coal refuse areas and slurry impoundments at a number of our mines. Such areas and impoundments are subject to extensive regulation. Slurry impoundments have been known to fail, releasing large volumes of coal slurry into the surrounding environment. Structural failure of an impoundment can result in extensive damage to the environment and natural resources, such as bodies of water that the coal slurry reaches, as well as liability for related personal injuries and property damages and injuries to wildlife. Some of our impoundments overlie mined out areas, which could pose a heightened risk of failure and of damages arising out of failure. If one of our impoundments were to fail, we could be subject to substantial claims for the resulting environmental contamination and associated liability, as well as for civil or criminal fines and penalties.

Drainage flowing from or caused by mining activities can be acidic with elevated levels of dissolved metals, a condition referred to as "acid mine drainage" (AMD). The treating of AMD can be costly. Although we do not currently face material costs associated with AMD, it is possible that we could incur significant costs in the future.

These and other similar unforeseen impacts that our operations may have on the environment, as well as exposures to hazardous substances or wastes associated with our operations, could result in costs and liabilities that could materially and adversely affect us.

Changes in the legal and regulatory environment could complicate or limit our business activities, increase our operating costs or result in litigation.

The conduct of our businesses is subject to various laws and regulations administered by federal, state and local governmental agencies in the United States. These laws and regulations may change, sometimes dramatically,
as a result of political, economic or social events or in response to significant events. Certain recent developments particularly may cause changes in the legal and regulatory environment in which we operate and may affect our results or increase our costs or liabilities. Such legal and regulatory changes may include changes in:

- the processes for obtaining or renewing permits;
- the standards upon which permit terms and conditions are established;
- regulations for the protection of water, air or land, including but not limited to enactment of the SPR, new water quality standards, implementation of the CWR, revisions to the MATS and CASPR rules, or new MACT, NESHAPS or NAAQS under the CAA;
- costs associated with providing health care benefits to employees;
- health and safety standards;
- accounting standards;
- taxation requirements; and
- competition laws.

Although we are unable to quantify the full impact, implementing and complying with new laws and regulations could have an adverse impact on our business and results of operations and could result in harsher sanctions in the event of any violations. See Item 1 - “Business-Regulation and Laws.”

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

See Item 1 – “Business—Our Mining Operations” for specific information about our mining operations and see Item 13 – “Certain Relationships and Related-Party Transactions, and Director Independence” for specific information about our leases with related parties.

Coal Reserves

As of December 31, 2016, we controlled approximately 567 million tons of proven and probable coal reserves. Our coal reserve estimates were prepared by Weir International, Inc., a mining and geological consultant. Our coal reserve estimates are based on data obtained from our drilling activities and other available geologic data and are updated to reflect past coal production and acquisitions of coal properties.

Our coal reserve estimates include reserves that can be economically and legally extracted or produced at the time of their determination. In determining whether our reserves meet this economical and legal standard, we take into account, among other things, our potential ability or inability to obtain a mining permit, the possible necessity of revising a mining plan, changes in estimated future costs, changes in future cash flows caused by changes in mining permits, variations in quantity and quality of coal, and varying levels of demand and their effects on selling prices.

All of our proven and probable reserves are classified as thermal coal.

The following tables provide a summary of information regarding our coal reserves as of December 31, 2016, unless otherwise noted.

Mines (Commenced Operations)	Mining Method (3)	Clean Recoverable Coal(Proven and Probable Reserves)(1)				Production			Quality Specifications (As Received)(2)	
						Year Ended December 31,				
		Proven Reserves	Probable Reserves	Total		2016	2015	2014	Heat Value (Btu/ Lb)	SO2 Content (Lbs/ MMBtu)
						(Tons in thousands)				
Active mines										
Midway (July 2008)(5)	S	13,360	805	14,165	(4)	—	1,063	1,293	11,454	4.9
Equality Boot (September 2010)	S	11,597	18	11,615	(4)	1,645	2,169	2,803	11,458	5.1
Lewis Creek (June 2011)	S	7,016	203	7,219	(4)	945	817	971	11,323	4.8
Kronos Underground (September 2011)	U	29,191	1,739	30,930	(6)	2,137	2,440	2,515	11,747	4.6
Survant Underground (August 2015)	U	36,340	19,089	55,429	(4)	688	358	—	11,984	4.8
Total active mines		97,504	21,854	119,358		5,415	6,847	7,582		
Additional reserves										
Ken	S	17,166	3,854	21,020	(4)	—	—	—	11,808	5.0
Union/Webster	U	46,501	77,417	123,918		—	—	—	13,351	4.4
Thoroughbred	S/U	146,873	51,250	198,123		—	—	—	11,810	4.6
Other	S/U	78,932	25,173	104,105	(7)	474	1,227	1,763	11,623	5.4
Total additional reserves		289,472	157,694	447,166		474	1,227	1,763		
Total		386,976	179,548	566,524		5,889	8,074	9,345		

(1) For surface mines, clean recoverable tons are based on a 90% mining recovery, preparation plant yield at 1.55 specific gravity and a 95% preparation plant efficiency. For underground mines other than Union/Webster Counties, clean recoverable tons are based on a 50% mining recovery, preparation plant yield at 1.55 specific gravity and a 95% preparation plant efficiency. For Union/Webster Counties, clean recoverable tons are based on a 50% mining recovery, preparation plant yield at 1.60 specific gravity and a 95% preparation plant efficiency. "Proven and probable reserves" refers to coal that can be economically extracted or produced at the time of the reserve determination.
(2) Quality specifications displayed on an "as received" basis. If derived from multiple seams, data represents an average.
(3) U = Underground; S = Surface.
(4) Of these reserves, 79.19% of the interests controlled by Armstrong Energy were leased from Thoroughbred as of December 31, 2016. Effective January 1, 2017, 100.0% of the reserves were leased from Thoroughbred.
(5) The Midway mine was temporarily idled in December 2015.
(6) Based on internal estimates, recoverable reserves are split among the three mines that will produce coal from the underground properties and coal reserves located in Ohio County, Kentucky that are owned by Thoroughbred and leased to Armstrong Energy (the Elk Creek Reserves).
(7) Of these reserves, excluding an estimated 23.9 million tons of Elk Creek Reserves, 79.19% of the interests controlled by Armstrong Energy were leased from Thoroughbred as of December 31, 2016. Effective January 1, 2017, 100.0% of the reserves were leased from Thoroughbred.

	Clean Recoverable Tons (Proven and Probable Reserves)(1)				
	Owned	Leased	Total		Primary Transportation Method
		(In thousands)			
Midway (July 2008)(3)	—	14,165	14,165	(2)	Rail, barge & truck
Equality Boot (September 2010)	—	11,615	11,615	(2)	Barge
Lewis Creek (surface) (June 2011)	439	6,780	7,219	(2)	Rail, barge & truck
Kronos Underground (September 2011)	—	30,930	30,930	(4)	Rail, barge & truck
Survant Underground (August 2015)	—	55,429	55,429	(2)	Barge & truck
Total active mines	439	118,919	119,358		

(1) For surface mines, clean recoverable tons are based on a 90% mining recovery, preparation plant yield at 1.55 specific gravity and a 95% preparation plant efficiency. For underground mines other than Union/Webster Counties, clean recoverable tons are based on a 50% mining recovery, preparation plant yield at 1.55 specific gravity and a 95% preparation plant efficiency. For Union/Webster Counties, clean recoverable tons are based on a 50% mining recovery, preparation plant yield at 1.60 specific gravity and a 95% preparation plant efficiency. “Proven and probable reserves” refers to coal that can be economically extracted or produced at the time of the reserve determination.
(2) Of these reserves, 79.19% of the interests controlled by Armstrong Energy are leased from Thoroughbred as of December 31, 2016. Effective January 1, 2017, 100.0% of the reserves were leased from Thoroughbred.
(3) The Midway mine was temporarily idled in December 2015.
(4) Based on internal estimates, recoverable reserves are split among the three mines that will produce coal from the Elk Creek Reserves.

Item 3. Legal Proceedings

We are involved from time to time in various lawsuits and claims arising in the ordinary course of business. Although the outcomes of these lawsuits and claims are uncertain, we do not believe any of them will have a material adverse effect on our business, financial condition or results of operations. See Note 21, "Commitments and Contingencies," to our audited consolidated financial statements, included in Item 8 - "Financial Statements and Supplementary Data," of this Annual Report on Form 10-K for a discussion of significant legal matters.

Item 4. Mine Safety Disclosures

Information concerning mine safety violations and other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K is included in Exhibit 95.1 to this Annual Report on Form 10-K.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

There is no established public trading market for our common stock. The majority of the issued and outstanding common stock of Armstrong Energy, Inc. is held by members of management or Yorktown. See Item 12 — "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters." As of March 30, 2017, there were approximately 22 holders of record of our common stock.

We have not issued a dividend to any of our equity holders since our inception. The indenture governing our Notes contains covenants that limit our ability to pay dividends. See Item 7—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Item 6. Selected Financial Data

The following table presents our selected historical consolidated financial and operating data for the periods indicated for Armstrong Energy, Inc. and its subsidiaries. The selected historical financial data for the years ended December 31, 2016, 2015, 2014, 2013, and 2012, and the balance sheet data as of December 31, 2016, 2015, 2014, 2013, and 2012, are derived from the audited consolidated financial statements of Armstrong Energy, Inc.

Historical results are not necessarily indicative of results we expect in future periods. The following selected financial data should be read in conjunction with Item 7 – "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our consolidated financial statements and related notes appearing elsewhere in this Annual Report on Form 10-K.

	Year Ended December 31,				
	2016	2015[1]	2014	2013	2012
	(In thousands, except per ton amounts)				
Results of Operations Data					
Total revenues	$ 253,902	$ 360,900	$ 441,833	$ 415,282	$ 382,109
Costs and expenses	275,733	494,499	438,289	405,370	375,461
Operating (loss) income	(21,831)	(133,599)	3,544	9,912	6,648
Interest expense, net	(34,183)	(34,685)	(33,134)	(35,563)	(19,200)
Other (expense) income, net	(2,699)	5,486	758	579	(5,487)
Loss before income taxes	(58,713)	(162,798)	(28,832)	(25,072)	(18,039)
Income taxes	(117)	657	—	—	—
Net loss	(58,830)	(162,141)	(28,832)	(25,072)	(18,039)
Less: income (loss) attributable to non-controlling interest	—	—	—	—	—
Net loss attributable to common stockholders	$ (58,830)	$ (162,141)	$ (28,832)	$ (25,072)	$ (18,039)

	Year Ended December 31,				
	2016	2015[1]	2014	2013	2012
Balance Sheet Data (at period end)					
Total assets	$ 334,155	$ 380,711	$ 524,734	$ 535,995	$ 551,970
Working capital	47,362	52,456	43,501	42,042	48,873
Total long-term debt(2)	207,257	211,910	196,176	195,126	195,557
Total stockholders' (deficit) / equity	(93,807)	(35,281)	124,857	156,943	182,662
Other Data					
Tons sold (unaudited)	5,958	7,791	9,419	9,266	8,521
Tons produced (unaudited)	5,889	8,074	9,345	9,315	8,663
Sales price per ton (unaudited)	$ 42.62	$ 46.32	$ 46.91	$ 44.82	$ 44.84
Net cash provided by (used in):					
Operating activities	$ 3,010	$ 36,243	$ 41,145	$ 32,944	$ 30,769
Investing activities	(2,529)	(18,925)	(24,437)	(32,581)	(46,524)
Financing activities	(10,593)	(9,219)	(8,822)	(8,863)	56,307
Adjusted EBITDA(3) (unaudited)	33,224	68,483	61,760	58,156	50,854
Adjusted EBITDA is calculated as follows (unaudited):					
Net loss	$ (58,830)	$ (162,141)	$ (28,832)	$ (25,072)	$ (18,039)
Income taxes	117	(657)	—	—	—
Depreciation, depletion and amortization	31,040	47,259	46,512	38,838	35,410
Asset retirement obligation expenses	1,428	1,966	1,624	1,648	1,399
Non-cash production royalty to related party	7,121	7,879	8,269	6,761	5,695
Interest expense, net	34,183	34,685	33,134	35,563	19,200
Asset impairment and restructuring charges	4,431	138,679	—	—	—
Costs incurred evaluating strategic alternatives	2,389	—	—	—	—
Non-cash charge on settlement with Thoroughbred	10,542	—	—	—	—
Loss on extinguishment of debt	403	—	—	—	3,953
Non-cash employee benefit expense	419	668	1,127	—	—
Non-cash stock compensation expense (income)	(19)	145	(74)	418	697
Loss on settlement of interest rate swap	—	—	—	—	1,409
Loss on deferment of equity offering	—	—	—	—	1,130
	$ 33,224	$ 68,483	$ 61,760	$ 58,156	$ 50,854

(1) Due to the challenging market conditions, our 2015 results were negatively impacted. As a result, we recognized asset impairment and restructuring charges of $138.7 million. See Note 4, "Asset Impairment and Restructuring Charges," to our audited consolidated financial statements, included in Item 8 - "Financial Statements and Supplementary Data" of this Annual Report on Form 10-K.

(2) Amount does not include $147.5 million, $128.8 million, $110.7 million, $106.3 million and $98.4 million of certain long-term obligations to Thoroughbred as of December 31, 2016, 2015, 2014, 2013 and 2012, respectively, which are characterized as financing transactions due to our continuing involvement in the lease of the related land and mineral reserves.

(3) Adjusted EBITDA is a non-GAAP financial measure, and, when analyzing our operating performance, investors should use Adjusted EBITDA in addition to, and not as an alternative for, operating income (expense) and net income (loss) (each as determined in accordance with GAAP). We use Adjusted EBITDA as a supplemental financial measure.

Adjusted EBITDA is defined as net income (loss) before deducting net interest expense, income taxes, depreciation, depletion and amortization, asset retirement obligation expenses, costs incurred evaluating strategic alternatives, non-cash production royalty to related party, asset impairment and restructuring charges, non-cash charge on settlement with Thoroughbred, loss on settlement of interest rate swap, loss on deferment of equity offering, non-cash stock compensation expense (income), non-cash employee benefit expense, and (gain) loss on extinguishment of debt.

Adjusted EBITDA, as used and defined by us, may not be comparable to similarly titled measures employed by other companies and is not a measure of performance calculated in accordance with GAAP. There are significant limitations to using Adjusted EBITDA as a measure of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect our net income or loss, the lack of comparability of results of operations of different companies and the different methods of calculating Adjusted EBITDA reported by different companies. Adjusted EBITDA should not be considered in isolation or as a substitute for analysis of our results as reported under GAAP.

For example, Adjusted EBITDA does not reflect:

- cash expenditures, or future requirements, for capital expenditures or contractual commitments;
- changes in, or cash requirements for, working capital needs;
- the significant interest expense, or the cash requirements necessary to service interest or principal payments, on debt; and
- any cash requirements for assets being depreciated and amortized that may have to be replaced in the future.

Adjusted EBITDA does not represent funds available for discretionary use because those funds are required for debt service, capital expenditures, working capital and other commitments and obligations. However, our management team believes Adjusted EBITDA is useful to an investor in evaluating our company because this measure:

- is widely used by investors in our industry to measure a company's operating performance without regard to items excluded from the calculation of such term, which can vary substantially from company to company depending upon accounting methods and book value of assets, capital structure and the method by which assets were acquired, among other factors; and
- helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure, which is useful for trending, analyzing and benchmarking the performance and value of our business.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with Item 6 – "Selected Financial Data" and our consolidated financial statements and related notes appearing elsewhere in this Annual Report on Form 10-K. This discussion and analysis contains forward-looking statements that involve risks and uncertainties. Our actual results may differ materially from those anticipated in these forward-looking statements as a result of a variety of risks and uncertainties, including those described under "Cautionary Statement Concerning Forward-Looking Statements" and Item 1A – "Risk Factors." We assume no obligation to update any of these forward-looking statements.

Overview

Armstrong Energy is a producer of low chlorine, high sulfur thermal coal from the Illinois Basin, with both surface and underground mines. We market our coal primarily to proximate and investment-grade electric utility companies as fuel for their steam-powered generators. Based on 2016 production, we are the sixth largest producer in the Illinois Basin and the second largest in Western Kentucky. We were formed in 2006 to acquire and develop a large coal reserve holding. We commenced production in the second quarter of 2008 and currently operate five mines, including three surface and two underground. We control approximately 567 million tons of proven and probable coal reserves. We also own and operate three coal processing plants, which support our mining operations. From our reserves, we mine coal from multiple seams that, in combination with our coal processing facilities, enhance our ability to meet customer requirements for blends of coal with different characteristics. The locations of our coal reserves and operations, adjacent to the Green River, together with our river dock coal

handling and rail loadout facilities, allow us to optimize coal blending and handling, and provide our customers with rail, barge and truck transportation options.

We market our coal primarily to large utilities with coal-fired, base-load, scrubbed power plants under multi-year coal supply agreements. Our multi-year coal supply agreements usually have specific volume and pricing arrangements for each year of the agreement. These agreements allow customers to secure a supply for their future needs and provide us with greater predictability of sales volume and sales prices. At December 31, 2016, we had multi-year coal supply agreements with remaining terms ranging from one to four years, and we are contractually committed to sell 5.3 million tons of coal in 2017.

For each of 2016 and 2015, we produced 5.9 million and 8.1 million tons of coal, respectively, and, during the same periods, we sold 6.0 million and 7.8 million tons of coal, respectively. For the year ended December 31, 2016, our revenue from coal sales was $253.9 million, and we generated an operating loss of $21.8 million, net loss of $58.8 million, and Adjusted EBITDA of $33.2 million. Our revenue, operating loss, net loss and Adjusted EBITDA for the year ended December 31, 2015 were $360.9 million, $133.6 million, $162.1 million, and $68.5 million, respectively.

Our principal expenses related to the production of coal are labor and benefits, equipment, materials and supplies (explosives, diesel fuel and electricity), maintenance, royalties and state and federal severance taxes. Unlike some of our competitors, we employ a completely non-union workforce. Many of the benefits of our non-union workforce are related to higher productivity and are not necessarily reflected in our direct costs. In addition, while we typically do not pay our customers' transportation costs, they may be substantial and are often the determining factor in a coal consumer's contracting decision. The location of our coal reserves and current operations, adjacent to the Green River, together with our river dock coal handling and rail loadout facilities, allow us to optimize coal blending and handling and provide our customers with rail, barge and truck transportation options.

Going Concern

We have experienced recurring losses from operations, which has led to a substantial decline in cash flows from operating activities for the year ended December 31, 2016. Our current operating plan indicates that we will continue to incur losses from operations and generate negative cash flows from operating activities. In addition, we entered into a settlement agreement with Thoroughbred, effective March 29, 2017, whereby we agreed, among other things, to begin paying Thoroughbred all production royalties earned on or after January 1, 2017 in cash (see " - Recent Developments" for more information with respect to the settlement agreement). Our continuing operating losses, negative cash flow projections and other liquidity risks raise substantial doubt about whether we will meet our obligations as they become due within one year after the date of this report. As a result of this, as well as the continued uncertainty around future coal fundamentals, we have concluded there exists substantial doubt regarding our ability to continue as a going concern.

The accompanying consolidated financial statements have been prepared assuming we will continue as a going concern, which contemplates the realization of assets and liabilities and commitments in the normal course of business. The consolidated financial statements for the year ended December 31, 2016 do not include any adjustments that may result from uncertainty related to our ability to continue as a going concern. The report from our independent registered public accounting firm on our consolidated financial statements for the year ended December 31, 2016 includes an explanatory paragraph regarding our ability to continue as a going concern.

Due to our current financial outlook, we have undertaken steps to preserve our liquidity and manage operating costs, including controlling capital expenditures. Beginning in 2015, we undertook steps to enhance our financial flexibility and reduce cash outflows in the near term, including a streamlining of our cost structure and anticipated reductions in production volumes and capital expenditures. In addition, we are actively negotiating a restructuring with advisers to certain Holders of the Notes, who collectively beneficially own or manage in excess of 75% of the aggregate principal amount of the Notes.

We have engaged financial and legal advisers to assist us in restructuring our capital structure and evaluating other potential alternatives to address the impending liquidity constraints. However, there can be no assurance that any restructuring will be possible on acceptable terms, if at all. It may be difficult to come to an agreement that is acceptable to all of our creditors. Our failure to reach an agreement on the terms of a restructuring with our creditors would have a material adverse effect on our liquidity, financial condition and results of operations. In addition, if a successful restructuring with the holders of the Notes is not achieved, it may be necessary for us to file a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code in order to implement a restructuring, or our creditors could force us into an involuntary bankruptcy or liquidation.

For more information on the specific risks we face due to the above, see Item 1A - "Risk Factors."

Recent Developments

Claim of Event of Default by Bondholders

On December 30, 2016, Rhino Holdings, an entity wholly-owned by Yorktown, together with Rhino, Royal, and Rhino GP entered into the Option, pursuant to which Rhino received a call option, and Rhino Holdings received a put option, on all of the outstanding Company stock currently held by Yorktown, the majority owner of our outstanding common stock, under certain circumstances. The Option provides that Rhino can exercise the Option after 60 days following entry of an agreement regarding the restructuring of the Notes, but in no event earlier than January 1, 2018 and no later than December 31, 2019. In exchange for Rhino Holdings granting Rhino the Option to purchase Yorktown's holdings of Armstrong Energy stock, Rhino issued 5.0 million common units to Rhino Holdings upon the execution of the Option.

In connection with entry into the Option by the aforementioned parties, on February 2, 2017, we received notice from legal counsel representing certain of the Holders of the Notes that the Holders believe entry into the Option by the third-parties constitutes a Change of Control, as defined in the Indenture governing the Notes, and that an Event of Default occurred, as defined in the Indenture, when we failed to offer to purchase the Notes within 30 days following the purported Change of Control. However, counsel for the Holders also advised us that the Holders are not currently pursuing remedies under the Indenture related to the alleged Event of Default, but reserve their rights to do so at a future time. In addition, certain of our financing agreements include cross-default or cross-event of default provisions, which, if the aforementioned assertions were proven to be accurate, would result indirectly in an event of default under such financing arrangements.

We believe that neither a Change of Control nor an Event of Default as defined in the Indenture has occurred. To that end, we have advised legal counsel for the Holders that we dispute the allegations. No further action associated with these claims has been taken to date by us or the Holders.

Settlement Agreement with Thoroughbred

On December 16, 2016, we received notification from legal counsel for Thoroughbred Holdings, the general partner of Thoroughbred, disputing the calculation of deferred royalties and valuation of Jointly-Owned Property to be transferred pursuant to the terms of the Royalty Agreement. In the December 16th correspondence, counsel for Thoroughbred Holdings asserted that certain third-party valuations prepared in order to ascertain the amount of the Jointly-Owned Property to be transferred from us to Thoroughbred pursuant to the Royalty Agreement to satisfy production royalties due to Thoroughbred were inaccurate for fiscal year 2016 and prior years. Therefore, according to Thoroughbred, its ownership in the Jointly-Owned Property would have reached 100% during or prior to fiscal year 2016.

We promptly notified Thoroughbred that we disputed these assertions and requested information supporting Thoroughbred's arguments. Following our request, in a letter dated January 6, 2017, Thoroughbred Holding's CEO advised us that Thoroughbred, based on its analysis, concluded that our valuation of the remaining Jointly-Owned Property was significantly overstated, and using its valuation methodology, Thoroughbred would have been entitled to 100% ownership of the Jointly-Owned Property during the first half of 2016. Therefore, according to Thoroughbred's calculations, cash payment of production royalties was required for a portion of the royalties incurred during 2016 and thereafter. In addition, Thoroughbred questioned several of the inputs utilized in the valuation by us during prior years, therefore challenging the validity of the prior land and reserve transfers.

By subsequent letter dated February 15, 2017, Thoroughbred clarified that its valuation analysis ascertained that the fair market value of the entirety of the Jointly-Owned Property as of December 31, 2016 was not more than $35 million. In addition, Thoroughbred insisted that applying more conservative inputs to the valuations of prior periods resulted in the underpayment of production royalties by not less than $26.0 million and potentially in excess of $40.0 million through December 31, 2016. Thoroughbred's counsel, by separate letter dated February 15, 2017, also took exception to our calculation of the amount of deferred royalties for the year ended December 31, 2016, the amount of certain offsets from these deferred royalties by amounts due from Thoroughbred to us pursuant to an Administrative Services Agreement, and the offset of certain production royalties that we have overpaid to Thoroughbred on properties other than the Jointly-Owned Property. We subsequently notified Thoroughbred of our continued disagreement with their claims.

Following a series of negotiations, Armstrong and certain of its affiliates, and Thoroughbred Holdings and certain of its affiliates, entered into the Settlement Agreement, effective March 29, 2017, to resolve all of these claims and to avoid the

uncertainties of a potential lengthy arbitration. Under the terms of the Settlement Agreement, in exchange for our transfer of a 20.81% undivided interest in the transferable Jointly-Owned Property, we and Thoroughbred Holdings agreed to mutual waivers and releases related to the Royalty Agreement, the payment of production royalties or any other sums due under the leases prior to January 1, 2017, and the Administrative Services Agreement. Thoroughbred also waived and released any prior claims against us for lost or wasted coal or mining practices and operational decisions made by us; any other demands, claims, or assertions set forth in the various communications from Thoroughbred Holdings and its legal counsel to us; and any other claims arising from our administration of the leases prior to January 1, 2017. In addition, we agreed to begin paying Thoroughbred all production royalties earned on or after January 1, 2017 in cash pursuant to the existing lease terms, with royalties earned for January and February 2017 totaling $2.7 million being paid on March 31, 2017.

As a result of the Settlement Agreement, we recognized a non-cash charge in the year ending December 31, 2016 totaling $10.5 million related to the 9.86% increase in the Jointly-Owned Property transferred to resolve the aforementioned disputes. The 9.86% interest in the Jointly-Owned Property represents production royalties that were expected to be earned by Thoroughbred in the first half of 2017, which would have resulted in Thoroughbred's interest in the Jointly-Owned Property reaching 100.0%. Effective with the execution of the Settlement Agreement, amounts accrued to Thoroughbred totaling $11.7 million as of December 31, 2016 were forgiven as consideration for the transfer of the remaining interest in the Jointly-Owned Property. In addition, the Jointly-Owned Property that was the subject of the dispute has been leased and/or subleased by Thoroughbred to us in exchange for a production royalty effective January 1, 2017. As a result of our continuing involvement in the land and mineral reserves transferred to Thoroughbred, this transaction is accounted for as a financing arrangement, and, therefore, will result in an increase to the long-term obligation to Thoroughbred totaling $22.2 million during the first quarter of 2017.

Production Rationalization

On April 22, 2016, WARN Act notices were delivered to employees of one of our mining operations and related preparation plant in anticipation of closing the Parkway underground mine. During the second quarter of 2016, the decision was made to continue operating the Parkway underground mine until all economically recoverable coal was depleted and, in October 2016, the mine ultimately depleted its economically recoverable reserves and ceased production. This mine shipped approximately 0.5 million tons of coal during 2016.

We continue to evaluate our operations and cost structure, and we will continue to take actions to respond quickly to changing and challenging market conditions, including a reduction of general and administrative (G&A) expenses and overhead costs throughout the Company.

Evaluating the Results of Our Operations

We evaluate the results of our operations based on several key measures:

- our coal production, sales volume and weighted average sales prices;
- our cost of coal sales; and
- our Adjusted EBITDA, a non-GAAP financial measure.

Coal Production, Sales Volume and Sales Prices

We evaluate our operations based on the volume of coal we produce, the volume of coal we sell and the prices we receive for our coal. Because we sell substantially all of our coal under multi-year coal supply agreements, our coal production, sales volume and sales prices are largely dependent upon the terms of those contracts. The volume of coal we sell is also a function of the productive capacity of our mines and changes in our inventory levels and those of our customers.

Our multi-year coal supply agreements typically provide for a fixed price, or a schedule of fixed prices, over the contract term. In addition, the contracts typically contain price reopeners that provide for a market-based adjustment to the initial price after the initial years of those contracts have been fulfilled. These contracts would terminate if we cannot agree upon a market-based price with the customer. In addition, many of our multi-year coal supply agreements have full or partial cost pass through or inflation adjustment provisions; specifically, costs related to fuel, explosives and new government impositions are subject to certain pass-through provisions under many of our multi-year coal supply agreements. Cost pass-through provisions typically provide for increases in our sales prices in rising operating cost environments and for decreases in declining operating cost environments. Inflation adjustment provisions typically provide some protection in rising operating cost environments. We also

receive premiums, or pay penalties, based upon the actual quality of the coal we deliver, which is measured for characteristics such as heat (Btu), sulfur and moisture content.

We define our coal sales price per ton, or average sales price, as total coal sales divided by tons sold. We evaluate the price we receive for our coal on an average sales price per ton basis to evaluate marketing efforts and for market demand and trend analysis. The following table provides operational data with respect to our coal production, coal sales volume and average sales prices per ton for the periods indicated:

	Year Ended December 31,		
	2016	2015	2014
	(In thousands, except per ton amounts)		
Tons of Coal Produced	5,889	8,074	9,345
Tons of Coal Sold	5,958	7,791	9,419
Average Sales Price Per Ton	$ 42.62	$ 46.32	$ 46.91

Cost of Coal Sales

We evaluate our cost of coal sales on a cost per ton basis. Our cost of coal sales per ton represents our production costs divided by the tons of coal we sell. Our production costs include labor and associated benefits, fuel, lubricants, explosives, operating lease expenses, repairs and maintenance, royalties, selling and related expenses, and all other costs that are directly related to our mining operations, other than the cost of depreciation, depletion and amortization (DD&A) expenses. Our production costs also exclude any indirect expenses, such as G&A expenses.

Our production costs do not take into account the effects of any of the inflation adjustment or cost pass-through provisions in our multi-year coal supply agreements, as those provisions result in an adjustment to our coal sales price.

The following table provides summary information for the dates indicated relating to our cost of coal sales per ton produced:

	Year Ended December 31,		
	2016	2015	2014
	(In thousands, except per ton amounts)		
Tons of Coal Sold	5,958	7,791	9,419
Average Sales Price Per Ton	$ 42.62	$ 46.32	$ 46.91
Cost of Coal Sales Per Ton	$ 34.85	$ 36.31	$ 38.46

Adjusted EBITDA

We define Adjusted EBITDA as net income (loss) before deducting net interest expense, income taxes, depreciation, depletion and amortization, asset retirement obligation expenses, costs incurred evaluating strategic alternatives, non-cash production royalty to related party, asset impairment and restructuring charges, non-cash charge on settlement with Thoroughbred, loss on settlement of interest rate swap, loss on deferment of equity offering, non-cash stock compensation expense (income), non-cash employee benefit expense, and (gain) loss on extinguishment of debt.

Although Adjusted EBITDA is not a measure of performance calculated in accordance with GAAP, it is used as a supplemental financial measure by our management and by external users of our financial statements such as investors, commercial banks, research analysts and others, to assess the financial performance of our assets without regard to financing methods, capital structure or historical cost basis, the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness, our operating performance and return on investment compared to those of other companies in the coal energy sector, without regard to financing or capital structures, and the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities. Adjusted EBITDA has several limitations that are discussed under Item 6 – “Selected Financial Data,” where we also include a quantitative reconciliation of Adjusted EBITDA to the most directly comparable GAAP financial measure, which is net income (loss).

Factors That Affect Our Business

For the past three years, more than 90% of our coal sales were made under multi-year coal supply agreements. We intend to continue to enter into multi-year coal supply agreements for a substantial portion of our annual coal production, using our remaining production to take advantage of market opportunities as they present themselves. We believe our use of multi-year coal supply agreements reduces our exposure to fluctuations in the spot price for coal and provides us with a reliable and stable revenue base. Using multi-year coal supply agreements also allows us to partially mitigate our exposure to rising costs, to the extent those contracts have full or partial cost pass through provisions or inflation adjustment provisions. For example, certain of our contracts contain provisions that adjust the price paid for our coal in the event there is a change in the price of diesel fuel, a key cost component in our coal production. Certain of our other contracts contain provisions that permit us to seek additional price adjustments to account for changes in environmental and other laws and regulations to which we are subject, to the extent those changes increase the cost of our production of coal.

Certain of our multi-year coal supply agreements contain option provisions that give the customer the right to elect to purchase additional tons of coal each month during the contract term at a fixed price provided for in the contract. Our multi-year coal supply agreements that provide for these option tons typically require the customer to provide us with advance notice of an election to take these option tons. Because the price of these option tons is fixed under the terms of the contract, we could be obligated to deliver coal to those customers at a price that is below the market price for coal on the date the option is exercised. If our customers elect to receive these option tons, we believe we will have the operating flexibility to meet these requirements through increased production. Similarly, short-term changes by our customers in the amount of coal they purchase as a result of these option provisions may affect our average sales price per ton of coal in any given month or similarly narrow window.

We believe the other key factors that influence our business are:

- demand for coal;
- demand for electricity;
- economic conditions;
- the quantity and quality of coal available from competitors;
- competition for production of electricity from non-coal sources;
- domestic air emission standards and the ability of coal-fired power plants to meet these standards using coal produced from the Illinois Basin;
- legislative, regulatory and judicial developments, including delays, challenges to, and difficulties in acquiring, maintaining or renewing necessary permits or mineral or surface rights; and
- our ability to meet governmental financial security requirements associated with mining and reclamation activities.

For additional information regarding some of the risks and uncertainties that affect our business and the industry in which we operate, please see Item 1A – “Risk Factors.”

Recent Trends and Economic Factors Affecting the Coal Industry

Coal consumption and production in the United States have been driven in recent periods by several market dynamics and trends. According to the EIA, total coal consumption in the United States in 2016 decreased by approximately 67 million tons, or 8.3%, from 2015 levels. The decrease in U.S. domestic coal consumption during 2016 was primarily a function of decreased consumption in the electric power sector due to low natural gas prices, high inventory levels at utilities, and an increase in retirements of coal fired power plants. However, according to the EIA, coal is expected to remain a major source for electric power generation in the near term.

Results of Operations

Summary

The following table presents certain of our historical consolidated financial data for the periods indicated. The following table should be read in conjunction with Item 6 – “Selected Financial Data.”

	Year Ended December 31,		
	2016	2015	2014
		(In thousands, except per ton amounts)	
Results of Operations Data			
Total revenues	$ 253,902	$ 360,900	$ 441,833
Costs and expenses:			
Costs of coal sales	207,630	282,903	362,294
Production royalties to related party	7,121	7,879	8,269
Depreciation, depletion and amortization	31,040	47,259	46,512
Asset retirement obligation expenses	1,428	1,966	1,624
Asset impairment and restructuring charges	4,431	138,679	—
Non-cash charge on settlement with Thoroughbred	10,542	—	—
General and administrative expenses	13,541	15,813	19,590
Total costs and expenses	275,733	494,499	438,289
Operating (loss) income	(21,831)	(133,599)	3,544
Interest expense, net	(34,183)	(34,685)	(33,134)
Other, net	(2,699)	5,486	758
Loss before income taxes	(58,713)	(162,798)	(28,832)
Income taxes	(117)	657	—
Net loss	(58,830)	(162,141)	(28,832)
Less: income attributable to non-controlling interest	—	—	—
Net loss attributable to common stockholders	$ (58,830)	$ (162,141)	$ (28,832)
Other Data (1)			
Adjusted EBITDA (unaudited)	$ 33,224	$ 68,483	$ 61,760
Adjusted EBITDA per ton sold (unaudited)	5.58	8.79	6.56

(1) Adjusted EBITDA is a non-GAAP financial measure which represents net income (loss) before deducting net interest expense, income taxes, depreciation, depletion and amortization, asset retirement obligation expenses, costs incurred evaluating strategic alternatives, non-cash production royalty to related party, asset impairment and restructuring charges, non-cash charge on settlement with Thoroughbred, loss on settlement of interest rate swap, loss on deferment of equity offering, non-cash stock compensation expense (income), non-cash employee benefit expense, and (gain) loss on extinguishment of debt.

(2) For these purposes, "GAAP" refers to U.S. generally accepted accounting principles. Please see Item 6 – "Selected Financial Data" for a reconciliation of Adjusted EBITDA to net income (loss).

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

Overview

We reported revenue of $253.9 million for the year ended December 31, 2016, compared to $360.9 million for the year ended December 31, 2015. Coal sales decreased 23.5% to 6.0 million tons in 2016, compared to 7.8 million tons in the prior year. Our average sales price per ton in the year ended December 31, 2016 totaled $42.62 per ton, as compared to $46.32 per ton for the prior year. Our net loss and Adjusted EBITDA for 2016 totaled $58.8 million and $33.2 million, respectively, as compared to net loss and Adjusted EBITDA for 2015 of $162.1 million and $68.5 million, respectively.

Coal Production, Sales Volume, and Sales Price per Ton

Our coal production in 2016 of approximately 5.9 million tons decreased from production levels in 2015 of 8.1 million tons. For the years ended December 31, 2016 and 2015, we sold 6.0 million tons and 7.8 million tons, respectively. The decrease in overall production and corresponding decline in sales volumes is directly related to the decline in market demand driven by strict governmental regulations, increased competition from natural gas, and oversupply in the domestic coal market. In order to address the deterioration in market demand, effective December 31, 2015, we temporarily idled the Midway mine, reduced operations at our Parkway underground mine, which ultimately closed in October 2016, and reduced the workforce at

the related preparation plants. Partially offsetting the production decreases was the completion of the Survant underground mine in August 2015, which produced 0.7 million tons during the year ended December 31, 2016.

Our average sales price per ton decreased to $42.62 for the year ended December 31, 2016, from $46.32 for 2015. The decrease in 2016 is primarily due to the renewal of sales contracts at less favorable prices, as well as unfavorable transportation adjustments included as a component of the price in certain of our long-term coal supply agreements as a result of declining diesel prices experienced during 2016 when compared to 2015.

Revenue

Our coal sales revenue for the year ended December 31, 2016 decreased by $107.0 million, or 29.6%, to $253.9 million, as compared to $360.9 million for the year ended December 31, 2015. This decrease is primarily attributable to an unfavorable volume variance of approximately $84.9 million year-over-year due to lower contracted amounts in the current year from lower market demand. In addition, we experienced an unfavorable price variance of approximately $22.1 million, primarily due to lower overall contract pricing and unfavorable transportation adjustments during 2016 when compared to 2015.

Cost of Coal Sales

Cost of coal sales decreased 26.6% to $207.6 million in the year ended December 31, 2016, from $282.9 million in 2015. The decline is primarily attributable to selling 1.8 million tons less coal during the year ended December 31, 2016, as compared to 2015. On a per ton basis, our cost of coal sales decreased during the year ended December 31, 2016, as compared to 2015, from $36.31 per ton to $34.85 per ton. This decrease in the per ton amounts is due to lower repairs, maintenance and supplies costs at our underground mines, lower diesel fuel costs, favorable equipment lease and rental expenses, and lower blasting expenses at our surface operations due to a higher amount of unconsolidated overburden.

Production Royalty to Related Party

Production royalty to related party was $7.1 million and $7.9 million for the years ended December 31, 2016 and 2015, respectively. This amount relates to production royalties earned by our affiliate, Thoroughbred, from sales originating from our Kronos underground mine (where the mineral reserves are leased directly from Thoroughbred). The reduction is primarily due to sales volume declines experienced at our Kronos underground mine during the current year, partially offset by higher average sales prices in 2016 from coal sales originating from the Kronos underground mine due to customer mix, as compared to 2015.

Depreciation, Depletion and Amortization

DD&A expense decreased by $16.2 million, or 34.3%, to $31.0 million during the year ended December 31, 2016, as compared to 2015, where such favorable variance was driven by the reduced depreciable base subsequent to the impairment charge recognized in the third quarter of 2015, accelerated depreciation in the prior year of the capitalized mine development costs associated with the Lewis Creek underground mine resulting from the closure of the mine in the first quarter of 2015, and a decline in depletion from mining fewer tons in 2016.

Asset Retirement Obligation Expenses

Asset retirement obligation expenses decreased by $0.5 million, or 27.4%, to $1.4 million during the year ended December 31, 2016, as compared to 2015. The decrease is primarily attributable to changes in asset retirement cost estimates based on revisions to discount rates, reserve valuations and projected mine lives.

Asset Impairment and Restructuring Charges

Asset impairment and restructuring charges were $4.4 million and $138.7 million for the years ended December 31, 2016 and 2015, respectively. The current year charge related to certain advance royalties that could no longer be recouped, while the prior year charge was primarily associated with the write-down of the carrying value of our long-lived assets to their estimated fair value. Refer to Note 4, “Asset Impairment and Restructuring Charges,” to our audited consolidated financial statements, included in Item 8 - “Financial Statements and Supplementary Data,” of this Annual Report on Form 10-K for further information regarding the nature and composition of those charges.

Non-Cash Charge on Settlement with Thoroughbred

Non-cash charge on settlement with Thoroughbred totaled $10.5 million for the year ended December 31, 2016, which related to the resolution of a dispute with Thoroughbred involving certain related-party transactions. Refer to Note 13, "Related-Party Transactions," to our audited consolidated financial statements, included in Item 8 - "Financial Statements and Supplementary Data," of this Annual Report on Form 10-K for further information regarding the nature of the charge.

General and Administrative Expenses

G&A expenses were $13.5 million for the year ended December 31, 2016, which was $2.3 million, or 14.4%, lower than the year ended December 31, 2015. The decrease in the year ended December 31, 2016, as compared to 2015, is due primarily to lower labor and benefits expense ($1.4 million) and insurance costs ($0.8 million).

Interest Expense, Net

Interest expense, net is derived from the following components:

	Year Ended December 31,	
	2016	2015
	(In thousands)	
11.75% Senior Secured Notes due 2019	$ 23,500	$ 23,500
Long-term obligation to related party	7,604	10,049
Other, net	3,705	3,123
Capitalized interest	(626)	(1,987)
Total	$ 34,183	$ 34,685

Interest expense, net was $34.2 million for the year ended December 31, 2016, as compared to $34.7 million for the year ended December 31, 2015. The decrease is principally attributable to a decrease in the effective interest rate on the long-term obligation to related party due to revisions in the mine plan at December 31, 2015, partially offset by the increase in the average principal balance of the long-term obligation to related party from the completion of the reserve transfers to Thoroughbred in May 2015 and June 2016, which increased the principal balance on the obligation by $18.2 million and $16.4 million, respectively. In addition, partially offsetting the decline in interest expense is the recognition of a lesser amount of capitalized interest and an increase in interest expense associated with other long-term debt due to an increase in the average outstanding obligation in the current year, as compared to the same period of 2015.

Other, Net

Other, net for the year ended December 31, 2016 was expense of $2.7 million, as compared to income of $5.5 million for the year ended December 31, 2015. The decrease is primarily due to a $4.5 million refund during the second quarter of 2015 for a portion of Kentucky sales and use taxes paid on the purchase of certain energy and energy producing fuels for the period of 2008 through 2013. In addition, for the year ended December 31, 2016, we recognized costs associated with evaluating strategic alternatives of $2.4 million, incurred a loss on partial disposal of our equity investment in Thoroughbred of $0.3 million, and recognized a loss of $0.4 million associated with the termination of the Revolving Credit Facility.

Net Loss

Net loss for the year ended December 31, 2016 was $58.8 million, as compared to $162.1 million for the same period of 2015. The variance is driven primarily by the asset impairment and restructuring charge of $138.7 million taken in the prior year. Excluding the impact of the prior year asset impairment and restructuring charge, net loss increased by $35.4 million. The variance is driven by a decline in gross margin in the current year, the impairment charges recognized in 2016, the non-cash charge on the settlement with Thoroughbred recognized in 2016, and the refund in the second quarter of 2015 of certain previously paid Kentucky sales and use taxes, partially offset by lower DD&A and G&A expenses in the current year.

Adjusted EBITDA

Our Adjusted EBITDA for the year ended December 31, 2016 was $33.2 million, as compared to $68.5 million for the year ended December 31, 2015. The decrease in Adjusted EBITDA resulted primarily from a decline in gross margin of $31.7 million resulting from lower sales volume and average pricing in 2016, as compared to 2015, and the refund in the second

quarter of 2015 of certain previously paid Kentucky sales and use taxes. Such reduction was partially offset by lower G&A expenses, exclusive of stock compensation expense, experienced in the current year.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

Overview

We reported revenue of $360.9 million for the year ended December 31, 2015, compared to $441.8 million for the year ended December 31, 2014. Coal sales decreased 17.3% to 7.8 million tons in 2015, compared to 9.4 million tons in 2014. Our average sales price per ton in the year ended December 31, 2015 totaled $46.32 per ton, as compared to $46.91 per ton for the prior year. Our net loss and Adjusted EBITDA for 2015 totaled $162.1 million and $68.5 million, respectively, as compared to net loss and Adjusted EBITDA for 2014 of $28.8 million and $61.8 million, respectively.

Coal Production, Sales Volume, and Sales Price per Ton

Our coal production in 2015 of approximately 8.1 million tons decreased from production levels in 2014 of 9.3 million tons. For the years ended December 31, 2015 and 2014, we sold 7.8 million tons and 9.4 million tons, respectively. The decrease in overall production and corresponding decline in sales volumes is directly related to the deteriorating market demand driven by strict governmental regulations, increased competition from natural gas, mild weather in the second half of 2015, and oversupply in the domestic coal market. Partially offsetting the production decreases was the addition of the Survant Underground mine in August 2015, which produced 0.4 million tons during the year.

Our average sales price per ton decreased to $46.32 for the year ended December 31, 2015, from $46.91 for 2014. The per ton decrease in 2015 is primarily due to unfavorable transportation adjustments included as a component of the price in certain of our long-term coal supply agreements as a result of declining diesel prices, partially offset by annual price increases on certain of our multi-year coal supply agreements.

Revenue

Our coal sales revenue for the year ended December 31, 2015 decreased by $80.9 million, or 18.3%, to $360.9 million, as compared to $441.8 million for the year ended December 31, 2014. This decrease is primarily attributable to an unfavorable volume variance of approximately $76.3 million year-over-year due to production and delivery issues during the first quarter of 2015 resulting from the inclement weather experienced in western Kentucky and a decline in customer demand resulting in the delay of shipments during the second half of the year. In addition, we experienced an unfavorable price variance of approximately $4.6 million driven primarily by unfavorable transportation adjustments.

Cost of Coal Sales

Cost of coal sales decreased 21.9% to $282.9 million in the year ended December 31, 2015, from $362.3 million in 2014. The decline is primarily attributable to selling 1.6 million tons less coal during the year ended December 31, 2015, as compared to 2014. On a per ton basis, our cost of coal sales decreased during the year ended December 31, 2015, as compared to 2014, from $38.46 per ton to $36.31 per ton. This decrease in the per ton amounts is due to favorable repair and maintenance costs experienced at our underground mines, lower blasting costs incurred by our surface mines, lower fuel costs and better mining conditions experienced during the year ended December 31, 2015, partially offset by the impacts of adverse weather conditions that occurred in the first quarter of 2015.

Production Royalty to Related Party

Production royalty to related party was $7.9 million and $8.3 million for the years ended December 31, 2015 and 2014, respectively. This amount relates to production royalties earned by our affiliate, Thoroughbred, from sales originating from our Kronos underground mine (where the mineral reserves are leased directly from Thoroughbred). Sales volume declines experienced at our Kronos underground mine during the year ended December 31, 2015, along with slightly lower average prices in the current year, resulted in the decline in the production royalty earned by Thoroughbred in the year ended December 31, 2015, as compared to 2014.

Depreciation, Depletion and Amortization

DD&A expense increased by $0.7 million, or 1.6%, to $47.3 million during the year ended December 31, 2015, as compared to 2014. The increase is primarily due to the accelerated depreciation of the capitalized mine development costs associated with the Lewis Creek underground mine resulting from the closure of the mine in the first quarter of 2015 and the impact of the revision during the first quarter of 2015 to the useful lives of a portion of the machinery and equipment associated with certain of our surface mines. The increase was partially offset by lower depletion expense associated with reduced mine output in 2015 and lower DD&A in the fourth quarter of 2015 from the reduced depreciable base subsequent to the impairment charge recognized in the third quarter of 2015.

Asset Retirement Obligation Expenses

Asset retirement obligation expenses increased by $0.3 million, or 21.1%, to $2.0 million during the year ended December 31, 2015, as compared to 2014. The increase is primarily attributable to changes in asset retirement cost estimates based on revisions to discount rates, reserve valuations and projected mine lives.

Asset Impairment and Restructuring Charges

Asset impairment and restructuring charges were $138.7 million for the year ended December 31, 2015 and consisted of long-lived asset impairments of $137.7 million related to mineral rights and other property, plant, and equipment and employee termination benefits of $1.0 million. Refer to Note 4, “Asset Impairment and Restructuring Charges,” to our audited consolidated financial statements, included in Item 8 - “Financial Statements and Supplementary Data,” of this Annual Report on Form 10-K for further information regarding the nature and composition of those charges.

General and Administrative Expenses

G&A expenses were $15.8 million for the year ended December 31, 2015, which was $3.8 million, or 19.3%, lower than the year ended December 31, 2014. The decrease in the year ended December 31, 2015, as compared to 2014, is due primarily to lower labor and benefits expense and non-income related taxes.

Interest Expense, Net

Interest expense, net is derived from the following components:

	Year Ended December 31,	
	2015	2014
	(In thousands)	
11.75% Senior Secured Notes due 2019	$ 23,500	$ 23,500
Long-term obligation to related party	10,049	7,993
Other, net	3,123	2,614
Capitalized interest	(1,987)	(973)
Total	$ 34,685	$ 33,134

Interest expense, net was $34.7 million for the year ended December 31, 2015, as compared to $33.1 million for the year ended December 31, 2014. The increase is principally attributable to an increase in the effective interest rate on the long-term obligation to related party due to revisions in the mine plan at December 31, 2015 and the increase in the principal balance of the long-term obligation to related party from the completion of the reserve transfers to Thoroughbred in October 2014 and May 2015, which increased the principal balance on the obligation by $6.1 million and $18.2 million, respectively. The year-over-year increase in interest expense was partially offset by a higher amount of capitalized interest during the year ended December 31, 2015, as compared to 2014.

Other, Net

Other, net for the year ended December 31, 2015 and 2014 was $5.5 million and $0.8 million, respectively. The increase is due to a $4.5 million refund during the second quarter of 2015 for a portion of Kentucky sales and use taxes paid on the purchase of certain energy and energy producing fuels for the period of 2008 through 2013.

Net Loss

Net loss for the year ended December 31, 2015 was $162.1 million, as compared to $28.8 million for the same period of 2014. The increase in net loss is largely due to the asset impairment and restructuring charges of $138.7 million, lower gross margin of $1.5 million, and higher interest expense of $1.6 million, partially offset by the refund of certain previously paid Kentucky sales and use taxes during the second quarter of 2015 and lower G&A expenses of $4.5 million and $3.8 million, respectively.

Adjusted EBITDA

Our Adjusted EBITDA for the year ended December 31, 2015 was $68.5 million, as compared to $61.8 million for the year ended December 31, 2014. The increase in Adjusted EBITDA resulted primarily from the $4.5 million Kentucky sales and use tax refund during the second quarter of 2015 and lower G&A costs during the year, exclusive of stock compensation expense.

Liquidity and Capital Resources

Liquidity

The principal indicators of our liquidity are our cash on hand and, prior to its termination, availability under our Revolving Credit Facility. As more fully described below, we terminated our Revolving Credit Facility effective November 14, 2016. Our available liquidity as of December 31, 2016 was $57.5 million, which was comprised solely of cash on hand.

Our business is capital intensive and requires substantial capital expenditures for purchasing, upgrading and maintaining equipment used in mining our reserves, as well as complying with applicable environmental laws and regulations. Our principal liquidity requirements are to finance current operations; fund capital expenditures, including acquisitions from time to time; satisfy reclamation obligations; and service our debt. Historically, our primary sources of liquidity to meet these needs have been cash generated by our operations, and to a lesser extent, borrowings under our credit facilities and contributions from our equity holders.

We manage our exposure to changing commodity prices for our long-term coal contract portfolio through the use of multi-year coal supply agreements. We generally enter into fixed price, fixed volume supply contracts with terms greater than one year with customers with whom we have historically had limited collection issues. Our ability to satisfy debt service obligations, fund planned capital expenditures, and make acquisitions will depend upon our future operating performance, which will be affected by prevailing economic conditions in the coal industry and financial, business and other factors, some of which are beyond our control.

We have experienced recurring losses from operations, which has led to a substantial decline in cash flows from operating activities for the year ended December 31, 2016. Our current operating plan indicates that we will continue to incur losses from operations and generate negative cash flows from operating activities. In addition, we entered into a settlement agreement with Thoroughbred, effective March 29, 2017, whereby we agreed, among other things, to begin paying Thoroughbred all production royalties earned on or after January 1, 2017 in cash (see " - Recent Developments" for more information with respect to the settlement agreement). Our continuing operating losses, negative cash flow projections and other liquidity risks raise substantial doubt about whether we will meet our obligations as they become due within one year after the date of this report. As a result of this, as well as the continued uncertainty around future coal fundamentals, we have concluded there exists substantial doubt regarding our ability to continue as a going concern.

The accompanying consolidated financial statements have been prepared assuming we will continue as a going concern, which contemplates the realization of assets and liabilities and commitments in the normal course of business. The consolidated financial statements for the year ended December 31, 2016 do not include any adjustments that may result from uncertainty related to our ability to continue as a going concern. Additionally, the report from our independent registered public accounting firm on our consolidated financial statements for the year ended December 31, 2016 includes an explanatory paragraph regarding our ability to continue as a going concern.

Due to our current financial outlook, we have undertaken steps to preserve our liquidity and manage operating costs, including controlling capital expenditures. Beginning in 2015, we undertook steps to enhance our financial flexibility and reduce cash outflows in the near term, including a streamlining of our cost structure and anticipated reductions in production volumes and capital expenditures. In addition, we are actively negotiating a restructuring with advisers to certain Holders of the Notes, who collectively beneficially own or manage in excess of 75% of the aggregate principal amount of the Notes.

We have engaged financial and legal advisers to assist us in restructuring our capital structure and evaluating other potential alternatives to address the impending liquidity constraints. However, there can be no assurance that any restructuring will be possible on acceptable terms, if at all. It may be difficult to come to an agreement that is acceptable to all of our creditors. Our failure to reach an agreement on the terms of a restructuring with our creditors would have a material adverse effect on our liquidity, financial condition and results of operations. In addition, if a successful restructuring with the holders of the Notes is not achieved, it may be necessary for us to file a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code in order to implement a restructuring, or our creditors could force us into an involuntary bankruptcy or liquidation.

Our long-term debt consisted of the following as of the dates indicated:

Type	December 31, 2016	December 31, 2015
	(In thousands)	
11.75% Senior Secured Notes due 2019	$ 191,191	$ 195,419
Other	16,066	23,020
	207,257	218,439
Less: current maturities	8,217	8,402
Total long-term debt	$ 199,040	$ 210,037

Senior Secured Notes due 2019

On December 21, 2012, we completed the $200.0 million Notes offering. The Notes were issued at an original issuance discount (OID) of 96.567%. The OID was recorded on our balance sheet as a component of long-term debt, and is being amortized to interest expense over the life of the Notes. As of December 31, 2016 and 2015, the unamortized OID was $3.6 million and $4.6 million, respectively. We incurred $8.4 million of deferred financing fees related to the Notes, which have been capitalized and are being amortized over the life of the Notes.

Interest on the Notes is due semiannually on June 15 and December 15 of each year, with the first payment made on June 15, 2013. We may redeem the Notes, in whole or in part, at any time during the twelve months commencing on December 15, 2016 at 105.875% of the principal amount redeemed, at any time during the twelve months commencing December 15, 2017 at 102.938% of the principal amount redeemed, and at any time after December 15, 2018 at 100.000% of the principal amount redeemed, in each case plus accrued and unpaid interest to the applicable redemption date.

Upon the occurrence of an event of a Change of Control (as defined in the indenture governing the Notes), unless we have exercised our right to redeem the Notes, we will be required to make an offer to purchase the Notes at a redemption price of 101.000%, plus accrued and unpaid interest to the date of repurchase.

Subject to certain customary release provisions, the Notes are fully and unconditionally guaranteed, jointly and severally, on a senior secured basis, by us and substantially all of our current and future domestic restricted subsidiaries (as defined). They are also secured, subject to certain exceptions and permitted liens, on a first-priority basis by substantially all of our and the guarantors' assets that do not secure the Revolving Credit Facility (see below), or any successor or replacement credit facility, on a first-priority basis. Subject to certain exceptions and permitted liens, the Notes will also be secured on a second-priority basis by a lien on the assets securing our obligations under the Revolving Credit Facility, or any successor or replacement credit facility, on a first-priority basis.

The indenture governing the Notes contains restrictive covenants which, among other things, limit the ability (subject to exceptions) of us and our restricted subsidiaries (as defined) to (i) incur additional indebtedness or issue preferred equity; (ii) pay dividends or distributions on or purchase our stock or our restricted subsidiaries' stock; (iii) make certain investments; (iv) use assets as security in other transactions; (v) create guarantees of indebtedness by restricted subsidiaries; (vi) enter into agreements that restrict dividends, distributions, or other payment by restricted subsidiaries; (vii) sell certain assets or merge with or into other companies; and (viii) enter into transactions with affiliates.

On February 2, 2017, we received notice from legal counsel representing certain of the Holders of the Notes regarding an alleged Event of Default. See Note 21, "Commitments and Contingencies," to our audited consolidated financial statements, included in Item 8 - "Financial Statements and Supplementary Data," of this Annual Report on Form 10-K for further information regarding this claim.

Revolving Credit Facility

Concurrently with the closing of the Notes offering on December 21, 2012, we entered into the Revolving Credit Facility, an asset-based revolving credit facility. The Revolving Credit Facility, which was subsequently terminated in November 2016, provided for a five-year, $50.0 million revolving credit facility that would expire on December 21, 2017. Borrowings under the Revolving Credit Facility may not exceed a borrowing base, as defined within the agreement. In addition, the Revolving Credit Facility included a $10.0 million letter of credit sub-facility and a $5.0 million swingline loan sub-facility. As of December 31, 2015, we had $16.7 million available for borrowing under the facility. We incurred $1.2 million of deferred financing fees related to the Revolving Credit Facility that were capitalized and amortized to interest expense over the life of the facility.

Interest and Fees

Borrowings under the Revolving Credit Facility bore interest, at our option, at a rate based on (i) LIBOR, plus a margin ranging from 3.5% to 4.0%, or (ii) a base rate, plus a margin ranging from 2.5% to 3.0%. Margins could be increased by 2.0% per annum during the existence of any event of default. We were also required to pay certain other fees with respect to the Revolving Credit Facility, including: (i) an unused commitment fee ranging from 0.50% to 0.375% in respect of unutilized commitments, (ii) a fronting fee equal to 0.25% per annum of the amount of outstanding letters of credit and (iii) customary annual administration fees.

Collateral and Guarantors

The Revolving Credit Facility was secured by substantially all of our and our subsidiaries' assets (other than certain excluded assets), with (i) a first priority lien on the ABL Priority Collateral (as defined) and (ii) a second priority lien on the Notes Priority Collateral (as defined). The Revolving Credit Facility was also guaranteed on a full and unconditional basis by our same subsidiaries that guarantee the Notes.

Restrictive Covenants and Other Matters

The Revolving Credit Facility included customary covenants that, subject to certain exceptions, restricted our ability and the ability of our subsidiaries to, among other things, incur indebtedness (including capital leases), create liens on assets, make investments, loans, guarantees, advances or acquisitions, pay dividends and distributions, liquidate, merge or consolidate, divest assets, engage in certain transactions with affiliates, create joint ventures or subsidiaries, change the nature of our business, change our fiscal year, issue stock, amend organizational documents, make capital expenditures and provide negative pledges on assets. In addition, at any time when (i) undrawn availability is less than the greater of (a) $10.0 million or (b) an amount equal to 20% of the borrowing base or (ii) an event of default had occurred and was continuing, we would have been required to maintain a fixed charge coverage ratio, calculated as of the end of each calendar month for the twelve months then ended, greater than 1.0 to 1.0. The fixed charge coverage ratio was defined as the ratio of consolidated EBITDA to fixed charges, which includes the sum of unfinanced capital expenditures, scheduled principal payments on indebtedness, cash interest payments, dividends, and cash taxes.

The Revolving Credit Facility also contained customary affirmative covenants and events of default. If an event of default occurred, the lenders under the Revolving Credit Facility would be entitled to take various actions, including the acceleration of amounts due under the facility and all actions permitted to be taken by a secured creditor.

During 2016, our fixed charge coverage ratio was less than 1.0-to-1.0, which would have required us to maintain minimum availability greater than $10.0 million if any amounts were drawn on the Revolving Credit Facility. Since its inception, we had not borrowed under the Revolving Credit Facility, and, therefore, were not subject to the requirements of the financial covenants included within the agreement. Due to the restrictions imposed as a result of not maintaining the minimum fixed charge coverage ratio, we made the decision to terminate the Revolving Credit Facility effective November 14, 2016. Pursuant to this termination, we recognized a loss of $0.4 million, which is included as a component of "Other, net" in the consolidated statement of operations, to write-off the remaining unamortized deferred financing costs associated with the Revolving Credit Facility.

Cash Flows

The following table reflects cash flows for the applicable periods:

	Year Ended December 31,		
	2016	2015	2014
		(In thousands)	
Net cash provided by (used in):			
Operating Activities	$ 3,010	$ 36,243	$ 41,145
Investing Activities	$ (2,529)	$ (18,925)	$ (24,437)
Financing Activities	$ (10,593)	$ (9,219)	$ (8,822)

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

Net cash provided by operating activities was $3.0 million for the year ended December 31, 2016, a decrease of $33.2 million from net cash provided by operating activities of $36.2 million for 2015. Operating results were negatively impacted during the year ended December 31, 2016 due to a decline in gross margin resulting primarily from lower shipments and average pricing during this period, as compared to 2015. Offsetting this decline is a reduction in DD&A and G&A expenses. Positively impacting cash flows from operations for the year ended December 31, 2016 was an increase in the net related party liabilities of $14.3 million due to the deferment of amounts owed to our affiliate, Thoroughbred, including interest and royalties earned on leased reserves, and a decrease in inventory due to the timing of shipments. Negatively impacting operating cash flows was a decrease in accounts payable and accrued and other liabilities due to the timing of payments. Cash flows from operations for the year ended December 31, 2015 were positively impacted by the receipt of a Kentucky sales and use tax refund totaling $4.5 million during the second quarter of 2015 and an increase in net related party liabilities of $16.3 million due to the deferment of amounts owed to Thoroughbred, including royalties earned on leased reserves. Negatively impacting operating cash flows in the prior year was an increase in inventory due to the timing of shipments and a decrease in accounts payable and accrued and other liabilities due to the timing of payments.

Net cash used in investing activities decreased $16.4 million to $2.5 million for the year ended December 31, 2016, compared to $18.9 million for 2015. The current year investment is primarily attributable to capital expenditures to maintain our existing fixed assets, partially offset by the receipt of $0.5 million for the partial disposal of our equity investment in Thoroughbred, as Yorktown exercised its right under the Second Amended and Restated Agreement of Limited Partnership of Thoroughbred Resources, LP to remove Elk Creek, GP, a wholly-owned subsidiary of Armstrong Energy, as the general partner of Thoroughbred, effective September 1, 2016. The prior year investment is largely attributable to capital expenditures for equipment and mine development associated with the opening of the Survant underground mine at our Parkway complex.

Net cash used in financing activities was $10.6 million for the year ended December 31, 2016, as compared to net cash used in financing activities of $9.2 million for the year ended December 31, 2015. The current year and prior year activity relates primarily to scheduled capital lease and other long-term debt payments.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

Net cash provided by operating activities was $36.2 million for the year ended December 31, 2015, a decrease of $4.9 million from net cash provided by operating activities of $41.1 million for the same period of 2014. Operating results were negatively impacted during 2015 due to a decline in gross margin resulting primarily from lower shipments during the year, as compared to 2014. Substantially offsetting this decline is a reduction in G&A expenses from lower labor and benefits expense. In addition, operating results were favorably impacted from the receipt of a Kentucky sales and use tax refund totaling approximately $4.5 million during the second quarter of 2015, which is included as a component of Other, net in the audited consolidated statement of operations. Positively impacting cash flows from operations for the year ended December 31, 2015 was an increase in the net related party liabilities of $16.3 million due to the deferment of amounts owed to our affiliate, Thoroughbred, including interest and royalties earned on leased reserves. Negatively impacting operating cash flows was an increase in inventory due to the timing of shipments and a decrease in accounts payable and accrued and other liabilities due to the timing of payments. Cash flows from operations for the year ended December 31, 2014 were positively impacted by a decrease in accounts receivable and inventory resulting from reduced production and shipments during the fourth quarter of 2014, as well as an increase in net related party liabilities of $14.8 million due to the deferment of amounts owed to Thoroughbred. Negatively impacting operating cash flows was an increase in other non-current assets during the year ended December 31, 2014 due to an increase in collateral posted against outstanding surety bonds, which are used to secure the performance of our reclamation obligations.

Net cash used in investing activities decreased $5.5 million to $18.9 million for the year ended December 31, 2015,

compared to $24.4 million for 2014. The 2015 investment is primarily attributable to capital expenditures for equipment and mine development associated with the opening of the Survant underground mine at our Parkway complex. The 2014 investment is attributable to capital expenditures to maintain our existing fixed assets and initial spending on the development of the Survant underground mine.

Net cash used in financing activities was $9.2 million for the year ended December 31, 2015, as compared to net cash used in financing activities of $8.8 million for the year ended December 31, 2014. The current year and prior year activity relates primarily to scheduled capital lease and other long-term debt payments.

Contractual Obligations

We have various commitments primarily related to long-term debt, including capital leases and operating lease commitments related to equipment. The following table provides details regarding our contractual cash obligations as of December 31, 2016:

	Payments Due by Period				
	Total	Less Than One Year	1-3 Years	3-5 Years	More Than Five Years
	(In thousands)				
Long-term debt obligations (principal and interest)	$287,726	$32,389	$255,307	$4	$26
Long-term obligation to related party(1)	767,746	7,881	21,113	19,355	719,397
Operating lease obligations	4,970	4,239	731	—	—
Capitalized lease obligations (principal and interest)	568	568	—	—	—
Purchase obligations	72	72	—	—	—
Total	$ 1,061,082	$ 45,149	$ 277,151	$ 19,359	$ 719,423

(1) Long-term obligation to related party is an obligation associated with a financing arrangement with Thoroughbred. Payments due are estimated based on current mine plans and estimated sales prices of the coal and will be revised as mine plans change. For 2016, we are deferring the payment of any production royalty amounts due to Thoroughbred. In consideration for granting the option to defer these payments, we granted to Thoroughbred the option to acquire an additional undivided interest in Jointly-Owned Property by engaging in a financing arrangement, under which we would satisfy payment of any deferred fees by selling part of our interest in the aforementioned coal reserves at fair market value for such reserves determined at the time of the exercise of such options. See Note 13, "Related-Party Transactions," to our audited consolidated financial statements, included in Item 8 - "Financial Statements and Supplementary Data" of this Annual Report on Form 10-K for further discussion of the related-party relationship with Thoroughbred.

As discussed in “-Recent Developments,” we entered into a settlement agreement with Thoroughbred, effective March 29, 2017, regarding a dispute over jointly owned land and mineral reserve interests that are leased and/or subleased by Thoroughbred to us in exchange for a production royalty. Pursuant to the settlement agreement, we (1) agreed, among other things, to the transfer of a 20.81% undivided interest in the transferable Jointly-Owned Property in exchange for certain mutual waivers and releases associated with the Royalty Agreement, the payment of production royalties or any other sums due under the leases prior to January 1, 2017, and the Administrative Services Agreement; and (2) we will begin paying Thoroughbred all production royalties earned on or after January 1, 2017 in cash pursuant to the existing lease terms. The settlement resulted in Thoroughbred’s interest in the Jointly-Owned Property being increased to 100.0% effective January 1, 2017. As a result, the timing of payments under our obligation to Thoroughbred increased by $2.1 million due within one year, $5.5 million due within one to three years, $5.1 million due within three to five years and $189.0 million due thereafter.

Capital Expenditures

Our mining operations require investments to expand, upgrade or enhance existing operations and to comply with environmental and safety regulations. In response to the challenging coal environment, we have sought to maintain a controlled, disciplined approach to capital spending in order to preserve liquidity. Our total capital expenditures for 2016 totaled $3.0 million, a decrease of approximately 85% compared to the prior year. We anticipate total capital expenditures for 2017 to be within a range of $9.0 million to $13.0 million. Management anticipates funding 2017 capital requirements with current cash balances and cash flows provided by operations. With respect to any significant development projects, we plan to

defer them to time periods beyond 2017 and will continue to evaluate the timing associated with those projects based on changes in overall coal supply and demand.

Mine Development Costs

Mine development costs are capitalized until production commences, other than production incidental to the mine development process, and are amortized on a units-of-production method based on the estimated proven and probable reserves. Mine development costs represent costs incurred in establishing access to mineral reserves and include costs associated with sinking or driving shafts and underground drifts, permanent excavations, roads and tunnels. The end of the development phase and the beginning of the production phase takes place when construction of the mine for economic extraction is substantially complete. Our estimate of when construction of the mine for economic extraction is substantially complete is based upon a number of assumptions, such as expectations regarding the economic recoverability of reserves, the type of mine under development, and the completion of certain mine requirements, such as ventilation. Coal extracted during the development phase is incidental to the mine's production capacity and is not considered to be a triggering event to shift the mine into the production phase.

During the third quarter of 2015, we completed development of the Survant underground mine at our Parkway complex to extract coal from the West Kentucky #8 seam. Annual production capacity at the mine is eventually expected to be expanded to approximately 2.4 million tons. Capitalized development costs for the new mine totaled approximately $25.2 million.

Off-Balance Sheet Arrangements

In the normal course of business, we are a party to certain off-balance sheet arrangements, which are not reflected in our consolidated balance sheets. These arrangements include guarantees and financial instruments with off-balance sheet risk, such as surety bonds and performance bonds. In our past, no claims have been made against these financial instruments. We do not expect any material adverse effects on our financial condition, results of operations or cash flows to result from these off-balance sheet arrangements.

Federal and state laws require us to secure certain long-term obligations such as mine closure and reclamation costs and other obligations. We typically secure these obligations by using surety bonds, an off-balance sheet instrument. The use of surety bonds is less expensive for us than the alternative of posting a 100% cash bond. To the extent that surety bonds become unavailable, we would seek to secure our reclamation obligations with letters of credit, cash deposits or other suitable forms of collateral. We also post performance bonds to secure our performance of various contractual obligations.

As of December 31, 2016, we had approximately $32.2 million in surety bonds outstanding to secure the performance of our reclamation obligations, which were supported by approximately $6.0 million of cash posted as collateral.

Related-Party Transactions

For information regarding our related-party transaction, see Note 13, "Related-Party Transactions," to our audited consolidated financial statements, included in Item 8 — "Financial Statements and Supplementary Data" of this Annual Report on Form 10-K.

Critical Accounting Policies and Estimates

Our consolidated financial statements are prepared in accordance with GAAP. In connection with the preparation of our consolidated financial statements, we are required to make assumptions and estimates about future events, and apply judgments that affect the reported amounts of assets, liabilities, revenue, expenses and the related disclosures. We base our assumptions, estimates and judgments on historical experience, current trends and other factors that management believes to be relevant at the time our consolidated financial statements are prepared. On a regular basis, we review the accounting policies, assumptions, estimates and judgments to ensure that our consolidated financial statements are presented fairly and in accordance with GAAP. However, because future events and their effects cannot be determined with certainty, actual results could differ from our assumptions and estimates, and such differences could be material.

Our significant accounting policies are discussed in Note 2, "Summary of Significant Accounting Policies," to our audited consolidated financial statements, included in Item 8 – "Financial Statements and Supplementary Data," of this Annual

Report on Form 10-K. We believe the following accounting estimates are the most critical to aid in fully understanding and evaluating our reported financial results, and they require our most difficult, subjective or complex judgments, resulting from the need to make estimates about the effect of matters that are inherently uncertain.

Property, Plant and Equipment

Property, plant and equipment are recorded at cost. Expenditures that extend the useful lives of existing plant and equipment are capitalized. Maintenance and repairs that do not extend the useful life or increase productivity are charged to operating expense as incurred. Plant and equipment are depreciated principally on the straight-line method over the estimated useful lives of the assets.

There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond our control. Our reserve estimates are based on engineering, economic and geological data assembled by our staff of geologists and engineers. Estimates of coal reserves necessarily depend upon a number of variables and assumptions, any one of which may vary considerably from actual results. These factors and assumptions relate to geological and mining conditions, which may not be fully identified by available exploration data and/or differ from our experiences in areas where we currently mine; the percentage of coal in the ground ultimately recoverable; historical production from the area compared with production from other producing areas; the assumed effects of regulation and taxes by governmental agencies; and assumptions concerning future coal prices, operating costs, capital expenditures, severance and excise taxes and development and reclamation costs.

For these reasons, estimates of the recoverable quantities of coal attributable to any particular group of properties, classifications of reserves based on risk of recovery and estimates of future net cash flows expected from these properties as prepared by different engineers, or by the same engineers at different times, may vary substantially. Actual production, revenue and expenditures with respect to our reserves will likely vary from estimates, and these variations may be material. Certain account classifications within our financial statements such as depreciation, depletion, and amortization and certain liability calculations such as asset retirement obligations may depend upon estimates of coal reserve quantities and values. Accordingly, when actual coal reserve quantities and values vary significantly from estimates, certain accounting estimates and amounts within our consolidated financial statements may be materially affected. Coal reserve values are reviewed annually, at a minimum, for consideration in our consolidated financial statements.

Impairment of Long-Lived Assets

We evaluate our long-lived assets used in operations for impairment as events and changes in circumstances indicate that the carrying amount of such assets might not be recoverable. Factors that would indicate potential impairment to be present include, but are not limited to, a sustained history of operating or cash flow losses, an unfavorable change in earnings and cash flow outlook, prolonged adverse industry or economic trends and a significant adverse change in the extent or manner in which a long-lived asset is being used or in its physical condition.

If there is an indication the carrying amount of an asset may not be recovered, the asset is evaluated by management where changes to significant assumptions are reviewed. Individual assets are grouped for impairment review purposes based on the lowest level for which there is identifiable cash flows that are largely independent of the cash flows of other groups of assets. When the sum of projected undiscounted cash flows is less than the carrying amount, impairment losses are recognized. In determining such impairment losses, we must determine the fair value for the assets in question in accordance with the applicable fair value accounting guidance. Once the fair value is determined, the appropriate impairment loss is recorded based on the difference between the carrying amount of the assets and their respective fair values.

During 2016, we recognized asset impairment charges of $4.4 million to write-off certain advance royalties that could no longer be recouped. In addition, due to the prolonged weakness in the U.S. coal markets, in the third quarter of 2015, we performed a comprehensive review of our current mining operations as well as potential future development projects to ascertain any potential impairment losses. We recorded an asset impairment charge of $137.7 million for the year ended December 31, 2015. Refer to Note 4, “Asset Impairment and Restructuring Charges,” to our audited consolidated financial statements, included in Item 8 - “Financial Statements and Supplementary Data,” of this Annual Report on Form 10-K for further discussion of the charges incurred in the current and prior years. No impairment charges were recorded in 2014.

Asset Retirement Obligation

Our asset retirement obligations primarily consist of spending estimates for surface land reclamation and support facilities at both surface and underground mines in accordance with applicable reclamation laws in the U.S., as defined by each mining

permit. Asset retirement obligations are determined for each mine using various estimates and assumptions, including, among other items, estimates of disturbed acreage as determined from engineering data, estimates of future costs to reclaim the disturbed acreage and the timing of these cash flows, discounted using a credit-adjusted, risk-free rate. As changes in estimates occur (such as mine plan revisions, changes in estimated costs, or changes in timing of the reclamation activities), the obligation and asset are revised to reflect the new estimate after applying the appropriate credit-adjusted, risk-free rate. If our assumptions do not materialize as expected, actual cash expenditures and costs that we incur could be materially different than currently estimated. Any difference between the recorded amount of the liability and the actual cost of reclamation will be recognized as a gain or loss when the obligation is settled. We expect our actual cost to reclaim our properties will be less than the expected cash flows used to determine the asset retirement obligation. However, regulatory changes could increase our obligation to perform reclamation and mine closing activities. Asset retirement obligation expense for the years ended December 31, 2016, 2015, and 2014 was $1.4 million, $2.0 million, and $1.6 million, respectively. At December 31, 2016 and 2015, our balance sheets reflected asset retirement obligation liabilities of $14.2 million and $14.1 million, respectively, including amounts classified as a current liability. See Note 16, "Asset Retirement Obligations and Reclamation," to our audited consolidated financial statements for additional details regarding our asset retirement obligations, included in Item 8 – “Financial Statements and Supplementary Data,” of this Annual Report on Form 10-K.

Income Taxes

We account for income taxes in accordance with accounting guidance that requires deferred tax assets and liabilities be recognized using enacted tax rates for the effect of temporary differences between the book and tax bases of recorded assets and liabilities. The guidance also requires that deferred tax assets be reduced by a valuation allowance if it is “more likely than not” that some portion or the entire deferred tax asset will not be realized. In our evaluation of the need for a valuation allowance, we take into account various factors, including the expected level of future taxable income and available tax planning strategies. If actual results differ from the assumptions made in our evaluation, we may record a change in valuation allowance through income tax expense in the period such determination is made. We believe that the judgments and estimates are reasonable; however, actual results could differ. See Note 17, "Income Taxes," to our audited consolidated financial statements for additional details regarding our accounting for income taxes, included in Item 8 – “Financial Statements and Supplementary Data,” of this Annual Report on Form 10-K.

Based on our cumulative loss position and after evaluating other available evidence, including the scheduled reversals of our deferred tax assets and deferred tax liabilities, we have concluded a valuation allowance is necessary for the excess of deferred tax assets over deferred tax liabilities.

We anticipate that until we re-establish a pattern of continuing profitability, we will not recognize any material income tax expense or benefit in our statement of operations for future periods, as pretax profits or losses generally will generate tax effects that will be offset by decreases or increases in the valuation allowance with no net effect on the statement of operations. If a pattern of continuing profitability is re-established and we conclude that it is more likely than not that deferred income tax assets are realizable, we will reverse any remaining valuation allowance, which will result in the recognition of an income tax benefit in the period that it occurs.

Long-Term Obligation to Related Party

We have entered into certain transactions with our affiliate, Thoroughbred, whereby we have sold an undivided interest in certain of our land and mineral reserves and subsequently entered into a lease agreement to mine the acquired mineral reserves in exchange for a production royalty. Due to our continuing involvement in the land and mineral reserves transferred, these transactions have been accounted for as financing arrangements and a long-term obligation has been established that is being amortized at an annual rate of 7% of the estimated gross revenue generated from the sale of the coal originating from the leased mineral reserves. The effective interest rate of the obligation is based on various estimates in future pricing and production quantities within our mine plans and is adjusted prospectively, as significant changes in our mine plans occur. As of December 31, 2016, the effective interest on the long-term obligation to related party was 6.42%. See Note 13, "Related-Party Transactions," to our audited consolidated financial statements for additional details regarding our related party obligations, included in Item 8 – “Financial Statements and Supplementary Data,” of this Annual Report on Form 10-K.

Newly Adopted Accounting Standards and Accounting Standards Not Yet Implemented

We are an “emerging growth company,” as defined in Section 2(a)(19) of the Securities Act, as modified by the JOBS Act. Section 107 of the JOBS Act also provides that an “emerging growth company” can take advantage of the extended transition period provided in Section 7(a)(2)(B) of the Securities Act for complying with new or revised accounting standards, and delay compliance with new or revised accounting standards until those standards are applicable to private companies.

However, we have chosen to opt out of any extended transition period, and, as a result, we will comply with new or revised accounting standards on the relevant dates on which adoption of such standards is required for non-emerging growth companies. Section 107 of the JOBS Act provides that our decision to opt out of the extended transition period for complying with new or revised accounting standards is irrevocable.

In February 2016, the Financial Accounting Standards Board (FASB) issued updated guidance regarding the accounting for leases. This update requires lessees to recognize a lease liability and a lease asset for all leases, including operating leases, with a term greater than 12 months on its balance sheet. The update also expands the required quantitative and qualitative disclosures surrounding leases. This update is effective for fiscal years beginning after December 15, 2018 and interim periods within those fiscal years, with earlier application permitted. This update will be applied using a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. We are currently evaluating the effect of this update on its consolidated financial statements.

In November 2015, the FASB issued guidance that eliminates the requirement to present deferred tax liabilities and assets as current and noncurrent in a classified balance sheet. Instead, entities will be required to classify all deferred tax assets and liabilities as noncurrent. The new guidance is effective for financial statements issued for annual periods beginning after December 15, 2016, and interim periods within those annual periods, with early adoption permitted. We adopted this standard as of December 31, 2015. While the adoption of this guidance impacted our balance sheet disclosure, it did not affect our results of operations or cash flows.

In April 2015, the FASB issued guidance requiring an entity to present deferred financing costs on the balance sheet as a direct deduction from the related debt liability as opposed to an asset. Amortization of the costs will continue to be reported as interest expense. In August 2015, the FASB issued an accounting standards update about the presentation and subsequent measurement of deferred financing costs associated with line-of-credit arrangements, which allows for the presentation of deferred financing costs as an asset regardless of whether or not there is an outstanding balance on the line-of-credit arrangement. The updates are effective for annual reporting periods (including interim reporting periods within those periods) beginning after December 15, 2015. We adopted these standards during the three months ended March 31, 2016. Prior to its termination, we reported the unamortized deferred financing costs associated with Revolving Credit Facility within other non-current assets, whereas unamortized deferred financing costs associated with the Notes have been reclassified for all periods presented.

In February 2015, the FASB issued guidance changing the requirements and analysis required when determining the reporting entity's need to consolidate an entity, including modifying the evaluation of limited partnerships variable interest status, the presumption that a general partner should consolidate a limited partnership, and the consolidation criterion applied by a reporting entity involved with variable interest entities. We adopted this guidance during the first quarter of 2016, and it did not have an impact on its historical consolidation conclusions.

In August 2014, the FASB issued guidance on management’s responsibility in evaluating, at each annual and interim reporting period, whether there is substantial doubt about an entity’s ability to continue as a going concern and to provide related footnote disclosures. The new guidance is effective for the annual period ending after December 15, 2016, and for annual periods and interim periods thereafter with early adoption permitted. We adopted this standard as of December 31, 2016. See Note 3, "Liquidity and Going Concern," to our audited consolidated financial statements, included in Item 8 - "Financial Statements and Supplementary Data" of this Annual Report on Form 10-K.

In May 2014, the FASB issued a comprehensive revenue recognition standard that will supersede nearly all existing revenue recognition guidance under U.S. GAAP. The standard requires revenue to be recognized when promised goods or services are transferred to a customer in an amount that reflects the consideration expected in exchange for those goods or services. The standard permits the use of either the full retrospective or modified retrospective transition method. This guidance is effective for annual and interim reporting periods beginning after December 15, 2017, with early adoption permitted to the original effective date of December 15, 2016. Our primary source of revenue is from the sale of coal through both short-term and long-term contracts, primarily with utilities, whereby revenue is currently recognized when risk of loss has passed to the customer. During 2016, we started our initial review of contracts with customers and do not currently anticipate any material change in the timing or method of recognizing revenue from our current practice. As such, we do not believe this new standard will have a material impact on our results of operations, financial condition or cash flows. We are planning to adopt the new standard as of January 1, 2018, utilizing the modified retrospective method.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

We defined market risk as the risk of economic loss as a consequence of the adverse movement of market rates and prices. We believe our principal market risks are commodity price risk and credit risk.

Commodity Price Risk

We sell most of the coal we produce under multi-year coal supply agreements. Historically, we have principally managed the commodity price risks from our coal sales by entering into multi-year coal supply agreements of varying terms and durations, rather than through the use of derivative instruments.

Some of the products used in our mining activities, such as diesel fuel, explosives and steel products for roof support used in our underground mining, are subject to price volatility. Through our suppliers, we utilize forward purchases to manage a portion of our exposure related to diesel fuel volatility. A hypothetical increase of $0.10 per gallon for diesel fuel would have negatively impacted our results of operations by $0.4 million for the year ended December 31, 2016. A hypothetical increase of 10% in steel prices would have negatively impacted our results of operations by $1.3 million for the year ended December 31, 2016. A hypothetical increase of 10% in explosives prices would have negatively impacted our results of operations by $0.5 million for the year ended December 31, 2016.

Credit Risk

Most of our coal sales are made to electric utilities. Therefore, our credit risk is primarily with domestic electric power generators. Our policy is to independently evaluate each customer's creditworthiness prior to entering into a transaction with the customer and to constantly monitor outstanding accounts receivable against established credit limits. When deemed appropriate, we will take steps to reduce credit exposure to customers that do not meet our credit standards or whose credit has deteriorated. Credit losses are provided for in the financial statements and have historically been minimal.

Seasonality

Our business has historically experienced some variability in its results due to the effect of seasons. Demand for coal-fired power can increase due to unusually hot or cold weather as power consumers use more air conditioning or heating. Conversely, mild weather can result in softer demand for our coal. Adverse weather conditions, such as floods or blizzards, can affect our ability to mine and ship our coal and our customers' ability to take delivery of coal.

Item 8. Financial Statements and Supplementary Data

The report of independent registered public accounting firm and the consolidated financial statements required by this Item are set forth on pages F-1 through F-37 of this report and are incorporated herein by reference.

Item 9. Changes in and Disagreements with Accountant on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Our disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC, and that such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure. Our management, including our Chief Executive Officer and Chief Financial Officer, reviewed and evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2016. Based upon such review and evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of the date of such evaluation to provide reasonable assurance that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms and that such information is accumulated and communicated to the Company's management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed under the supervision of our Chief Executive Officer and Chief Financial Officer, and effected by our board of directors, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our consolidated financial statements for external purposes in accordance with GAAP. Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based upon the framework in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 Framework). Based on our evaluation under this framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2016.

Changes in Internal Control over Financial Reporting

During the fourth quarter of 2016, there has been no change in the Company's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B. Other Information

Retirement of Named Executive Officer

By letter dated March 29, 2017, Kenneth E. Allen, our Executive Vice President and Chief Operating Officer, informed the Company of his intention to retire effective June 1, 2017. Upon his retirement, Mr. Allen will continue as a consultant to the Company to help support its operations. Also, in connection with his retirement, Mr. Allen's employment agreement will terminate effective June 1, 2017.

Settlement Agreement

On December 16, 2016, we received the first of multiple notifications from Thoroughbred Holdings, the general partner of Thoroughbred, disputing, among other things, the calculation of deferred royalties and valuation of Jointly-Owned Property to be transferred pursuant to the terms of the Royalty Agreement. Specifically, Thoroughbred Holdings asserted that (i) its ownership in the Jointly-Owned Property would have reached 100% during or prior to fiscal year 2016 but for various errors and inaccuracies in third-party valuations ascertaining the amount of the Jointly-Owned Property transferred by the Company to satisfy production royalties due to Thoroughbred pursuant to the terms of the Royalty Agreement; (ii) upon reaching 100% ownership of the Jointly-Owned Property during or prior to fiscal 2016, cash payment for production royalties would have been required thereafter; (iii) errors in the property valuation resulted in the underpayment of production royalties; and (iv) errors existed in the calculation of deferred royalties due which impacted offsets on amounts due by Thoroughbred under the Administrative Services Agreement and offsets of production royalties owed to Thoroughbred on other properties. The Company disputed Thoroughbred Holdings' claims and assertions.

Following negotiations, and in an effort to resolve all claims and avoid the costs and uncertainties associated with lengthy arbitration, the Company and certain of its affiliates entered into the Settlement Agreement with Thoroughbred Holdings and certain of its affiliates, effective March 29, 2017. Pursuant to the terms of the Settlement Agreement, (i) the Company transferred the remaining 20.81% undivided interest in the transferable Jointly-Owned Property to Thoroughbred; (ii) the Company and Thoroughbred Holdings agreed to mutual waivers and releases related to the Royalty Agreement, the Administrative Services Agreement, and the payment of production royalties and any other sums due under the leases prior to January 1, 2017; (iii) Thoroughbred Holdings waived and released any prior claims against the Company for lost or wasted coal or mining practices and operational decisions, claims arising from the Company's administration of the leases prior to January 1, 2017, and any other demands, claims and assertions set forth in various communications from Thoroughbred Holdings; and (iv) the Company agreed to begin paying Thoroughbred all production royalties earned on or after January 1, 2017 in cash pursuant to the existing lease terms, with royalties earned for January and February 2017 totaling $2.7 million being paid on March 31, 2017.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Executive Officers and Directors

Set forth below are the names, ages and positions of our executive officers and directors as of March 30, 2017. All directors are elected for a term of three years and serve until their successors are elected and qualified. All executive officers hold office until their successors are elected and qualified.

Name	Age	Position with the Company
J. Hord Armstrong, III	75	Executive Chairman (Class II)
Martin D. Wilson	55	President, Chief Executive Officer, and Director (Class I)
Kenneth E. Allen	70	Executive Vice President and Chief Operating Officer
Jeffrey F. Winnick	42	Vice President and Chief Financial Officer
Anson M. Beard, Jr.	80	Director (Class I)
James C. Crain	68	Director (Class III)
Richard F. Ford	80	Director (Class III)
Greg A. Walker	61	Director (Class II)

Biographical information concerning the directors and executive officers listed above is set forth below. The term of our Class I directors expires in 2018, the term of our Class II directors expires in 2019, and the term of our Class III directors expires in 2017.

J. Hord Armstrong, III—Mr. Armstrong served as Chairman and Chief Executive Officer, and as a member of the board of managers, of Armstrong Land Company, LLC, our predecessor (Predecessor), from its formation in 2006 until 2011. From 2011 through May 2015, Mr. Armstrong served as our Chairman and Chief Executive Officer. In May 2015, Mr. Armstrong became Executive Chairman of the Board. Previously, Mr. Armstrong worked for the Morgan Guaranty Trust Company and was elected Assistant Treasurer in 1967. He subsequently spent ten years with White Weld & Company as First Vice President until the firm was acquired by Merrill Lynch in 1978. Mr. Armstrong then joined Arch Mineral Corporation (Arch Mineral), St. Louis, as Treasurer (1978-1981), and ultimately became its Vice President and Chief Financial Officer (1981-1987). Mr. Armstrong left Arch Mineral in 1987, when he founded D&K Healthcare Resources, Inc. (D&K). Mr. Armstrong served as D&K's Chief Executive Officer from 1987 to 2005. D&K became a public company in 1992 and was acquired by McKesson Corporation in 2005. Mr. Armstrong served for nine years as a member of the Board of Trustees of the St. Louis College of Pharmacy, as well as a Director of Jones Pharma Incorporated. He was formerly Chairman of the Board of Trustees of the Pilot Fund, a registered investment company. He was also formerly a Director of BHA, Inc. of Kansas City, Missouri, and a Director of GeoMet, Inc. of Houston, Texas. He currently serves as Advisory Director of US Bancorp. The board selected Mr. Armstrong to serve as a director because of his extensive experience in the coal industry and public company management, as well as his previous tenure with our Company. The board believes his prior experiences afford him unique insights into our Company's strategies, challenges and opportunities.

Martin D. Wilson— Mr. Wilson served as our Predecessor's President, and as a member of our Predecessor's board of managers, from its formation in 2006 until 2011. From 2011 to July 2014, Mr. Wilson was our President. From July 2014 to May 2015, he served as our President and Chief Commercial Officer. In May 2015, Mr. Wilson was appointed President and Chief Executive Officer. From 1988 until 2005, Mr. Wilson served as President, Chief Operating Officer, and Director of D&K. From 1985 to 1988, Mr. Wilson was employed by KPMG Peat Marwick. Mr. Wilson served for nine years as a member of the Board of Trustees of the St. Louis College of Pharmacy, as well as previously served as a Director of Healthcare Distribution Management Association. The board selected Mr. Wilson to serve as a director because of his experience in finance, operations, commercial transactions and public company management.

Kenneth E. Allen—Mr. Allen served as our Predecessor's Vice President of Operations from 2007 until 2011. From 2011 to July 2014, Mr. Allen was our Executive Vice President of Operations. Since that time, he has served as our Executive Vice President and Chief Operating Officer. In December 2013, Mr. Allen was also named Chief Operating Officer of Armstrong Coal Company, Inc., a wholly-owned subsidiary of Armstrong Energy. Mr. Allen served as a member of our board of directors from May 2015 until his resignation, effective February 7, 2017. By letter dated March 29, 2017, Mr. Allen informed the Company of his intention to retire effective June 1, 2017. He started his career with Peabody Coal Company in 1967 and has more than 40 years of experience in the coal industry. In 1971, he moved into a supervisory position and continued to hold

various supervisory and management positions, including Chief Electrical Engineer, Mine Superintendent, Operations Manager and Vice President of Resource Development and Conservancy. Prior to joining our Company in 2007, Mr. Allen held the position of President and General Manager of Bluegrass Coal Company, a subsidiary of Peabody Energy Corporation. Mr. Allen is Chairman of the Upper Pond River Conservancy District, Vice Chairman of the Kentucky Reclamation Guaranty Fund Commission, a member of the Kentucky Workforce Investment Board of Directors and the Madisonville-Hopkins County Economic Development Board of Directors. He is a past member of the Kentucky Coal Council and the Kentucky Governors Council of Economic Advisors. He is past Chairman and current member of the Executive Boards of the Kentucky Coal Association and past Chairman and member of the Executive Board of the Western Kentucky Coal Association. The board selected Mr. Allen to serve as a director because of his vast knowledge of the coal industry and experience in operations.

Jeffrey F. Winnick - Mr. Winnick served as our Vice President and Controller from 2011 to September 2015, at which time he was appointed Vice President and Chief Financial Officer. Prior to joining the Company, Mr. Winnick was employed by Ernst & Young LLP, an international public accounting firm, for over 13 years. Mr. Winnick is a Certified Public Accountant.

Anson M. Beard, Jr.—Mr. Beard was appointed to our board in 2011. He joined Morgan Stanley & Co. as a Vice President to found Private Client Services in 1977. He was promoted to Principal in 1979 and Managing Director in 1980. In 1981, he was put in charge of the firm's Equity Division, responsible for sales and trading relationships with institutional and individual investors of all equity and related products worldwide. In 1987, he was elected to the firm's Management Committee and the board of directors of Morgan Stanley Group. Mr. Beard was also the former Chairman of Morgan Stanley Security Services, Inc., a subsidiary of Morgan Stanley Group, which engaged in stock borrowing/lending, customer and dealer clearance, international settlements and custody. He previously served as a Trustee of the Morgan Stanley Foundation, Vice Chairman of the National Association of Securities Dealers, and Chairman of its NASDAQ, Inc. subsidiary. In 1994, Mr. Beard retired and became an Advisory Director of Morgan Stanley. He continues to serve in this capacity. Mr. Beard was selected for board membership because of his past board and committee experience and his knowledge of securities markets and publicly traded companies.

James C. Crain—Mr. Crain was appointed to our board of directors in 2011. Mr. Crain has been in the energy industry for more than 35 years, both as an attorney and as an executive officer. In July 2013, Mr. Crain retired as President of Marsh Operating Company (Marsh), an investments management company, a position he held since 1989. Mr. Crain currently serves as an adviser to Marsh and is a private investor. Mr. Crain also serves as a consultant for Yorktown, where he advises certain oil and gas related portfolio companies in connection with their business activities. Before joining Marsh in 1984, Mr. Crain was a partner in the law firm of Jenkens & Gilchrist. Mr. Crain is a director of Enlink Midstream, LLC, a midstream natural gas company, and Approach Resources, Inc., an independent oil and natural gas company. Mr. Crain was also formerly a director of Crosstex Energy, Inc. and Crosstex Energy, GP, LLC, midstream natural gas companies, GeoMet, Inc., a natural gas exploration and production company, and Crusader Energy Group Inc., an oil and gas exploration and production company. The board selected Mr. Crain to serve as a director because of his extensive legal, investment and transactional experience, as well as his public company board experience.

Richard F. Ford—Mr. Ford was appointed to our board in 2011. Mr. Ford is the retired general partner of Gateway Associates, L.P., a venture capital management firm that he formed in 1984. Mr. Ford serves as a member of the board of directors and a member of the audit committee of Barry-Wehmiller Company. Mr. Ford is also currently a management consultant to Centene Corp. Until 2012, Mr. Ford served as a director of Stifel Financial Corp. He currently serves on the board of directors of Washington University in St. Louis, Missouri. The board selected Mr. Ford to serve as a director because of his substantial experience in the financial services industry. He also has considerable board and committee leadership experience at other publicly held and large private companies.

Greg A. Walker—Mr. Walker was appointed to our board of directors in 2011. From 2009 to 2011, he served as a Senior Vice President of Alpha Natural Resources, Inc., assisting with integration issues after the merger of Alpha Natural Resources, Inc. and Foundation Coal Holdings, Inc. From 2004 to 2009, Mr. Walker served as the Senior Vice President, General Counsel and Secretary of Foundation Coal Holdings, Inc. From 1999 to 2004, he served as the Senior Vice President, General Counsel and Secretary of RAG American Coal Holdings, Inc., which was the predecessor entity to Foundation Coal Holdings, Inc. From 1989 to 1999, he served in various capacities in the law department of Cyprus Amax Minerals Company. Mr. Walker spent three years in private law practice in Denver, Colorado from 1986 to 1989, and from 1981 to 1986, he held various positions within the law department of Mobil Oil Corporation. From 2005 to 2012, he was a member of the board of directors of the FutureGen Industrial Alliance, Inc., a not-for-profit entity whose global members were working with the U.S. Department of Energy to build and operate a commercial scale oxy-combustion coal-fired power plant with carbon dioxide capture and sequestration. From 2007 through 2010, he served as an appointee from the United States to the Coal Industry Advisory Board, an international advisory panel to the International Energy Administration with respect to matters regarding the production, use and demand for coal on a global basis. The board selected Mr. Walker to serve as a director because of his specialized

knowledge of the coal and energy industry and applicable regulations, as well as his experience in public company management.

Board of Directors and Board Committees

Our board currently consists of six directors. Our board has established the following committees: an audit committee, a compensation committee, a nominating and corporate governance committee and a conflicts committee. The composition and responsibilities of each committee are described below. Members serve on these committees until their resignation or until otherwise determined by our board.

Audit Committee

Messrs. Crain, Ford and Walker, each an independent director, serve on our audit committee. Mr. Ford is the chair of the audit committee. The committee assists our board in fulfilling its oversight responsibilities relating to: (i) the integrity of our financial statements, internal accounting, financial controls, disclosure controls and financial reporting processes, (ii) the independent auditors' qualifications and independence, (iii) the performance of our independent auditors and (iv) our compliance with legal and regulatory requirements. The board has determined that Mr. Ford qualifies as an "audit committee financial expert," as that term is defined in Item 407(d)(5) of Regulation S-K, as promulgated by the SEC.

Audit Committee Report

The responsibilities of the audit committee are provided in its charter, which has been approved by the board of directors of the Company.

In fulfilling its oversight responsibilities with respect to the December 31, 2016 financial statements, the audit committee, among other things, has:

- reviewed and discussed with management the Company's audited financial statements as of and for the fiscal year ended December 31, 2016, including a discussion of the quality and acceptability of our financial reporting and internal controls;
- discussed with the Company's independent registered public accounting firm the matters required to be discussed with the audit committee under generally accepted auditing standards, including Public Company Accounting Oversight Board (PCAOB) Auditing Standard No. 1301, *Communications with Audit Committees;*
- discussed with the Company's independent registered public accounting firm its independence from management and the Company, received and reviewed the written disclosures in the letter from the Company's independent registered public accounting firm as required by the PCAOB, and considered the compatibility of non-audit services with the Company's independent registered public accounting firm's independence; and
- discussed with the Company's independent registered public accounting firm the overall scope and plans for its audit.

Based on the reviews and discussions referred to above, the audit committee has recommended to the board of directors that the audited financial statements referred to above be included in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2016.

Members of the Audit Committee:

Richard F. Ford, *Chair of the Audit Committee*
James C. Crain
Greg A. Walker

Compensation Committee

Messrs. Beard, Ford and Walker, each an independent director, serve on our compensation committee. Mr. Beard is the chair of the compensation committee. The committee is responsible for discharging the board's responsibility relating to compensation of our executive officers and directors, evaluating the performance of our executive officers in light of our goals

and objectives and recommending to the board for approval our compensation plans, policies and programs. Each member of the committee is independent, a "non-employee director" for purposes of Rule 16b-3 under the Exchange Act, and an "outside director" for purposes of Section 162(m) of the Internal Revenue Code of 1986, as amended (the "Code").

The compensation committee has been tasked with the responsibility to establish and implement our compensation philosophy and objectives, administrate our executive and director compensation programs and plans, and review and approve the compensation of our named executive officers.

The compensation committee's responsibilities are specified in its charter. The compensation committee's functions and authority include, among other things:

- Establishment and annual review of corporate goals and objectives relevant to the compensation of the executive officers, including the chief executive officer;
- Evaluation of the executive officers' performance;
- Determination and approval of executive officer compensation;
- Administration of equity compensation plans, annual bonus and long-term incentive cash-based compensation plans;
- Review and approval of employment agreements and severance arrangements of all executive officers; and
- Management of risk relating to incentive compensation.

Nominating and Corporate Governance Committee

Messrs. Beard, Crain and Ford, each an independent director, serve on our nominating and corporate governance committee. Mr. Crain is the chair of this committee. The committee is responsible for: (i) assisting the board by identifying individuals qualified to become board members and recommending to our board nominees for election as director, (ii) leading the board in its annual performance review, (iii) recommending members and chairpersons for each committee to the board, (iv) monitoring the attendance, preparation and participation of individual directors and conducting a performance evaluation of each director prior to the time he or she is considered for re-nomination to the board of directors and (v) monitoring and evaluating corporate governance issues and trends.

Conflicts Committee

Messrs. Beard, Crain and Walker, each an independent director, serve on our conflicts committee. Mr. Walker is the chair of this committee. Mr. Crain is engaged in certain transactions with Yorktown that are unrelated to Armstrong matters and Mr. Beard is a minority holder of certain of the Notes. The committee is responsible for: (i) reviewing specific matters that the board believes may involve conflicts of interest, (ii) reviewing specific matters requiring action of the conflicts committee pursuant to any agreement to which we are a party, (iii) advising the board on actions to be taken by the committee upon the board's request and (iv) carrying out any other duties delegated to the conflicts committee by the board of directors.

Code of Ethics

We have adopted a code of business conduct and ethics applicable to all employees, including executive officers and directors. A copy of the code of business conduct and ethics is available on our website at *www.armstrongenergyinc.com*. Any amendments to, or waivers from, provisions of the code related to certain matters will be disclosed on our website.

Procedures for Nominating Directors

There have been no material changes to the procedures by which security holders may recommend nominees to the Company's Board of Directors during the fiscal quarter ended December 31, 2016.

Item 11. Executive Compensation

2016 Summary Compensation Table

The following table sets forth all compensation paid to our named executive officers for the years ending December 31, 2016 and 2015.

Name and Principal Position	Year	Salary	Bonus	All Other Compensation		Total
J. Hord Armstrong, III,	2016	$ 300,000	$ —	$ 60,212	(1)	$ 360,212
Executive Chairman	2015	$ 400,425	$ 100,000	$ 56,698		$ 557,123
Martin D. Wilson,	2016	$ 450,000	$ —	$ 36,819	(2)	$ 486,819
President and Chief Executive Officer	2015	$ 437,426	$ 110,000	$ 36,576		$ 584,002
Kenneth E. Allen (4)	2016	$ 200,000	$ 50,000	$ 234,165	(3)	$ 484,165
Executive Vice President and Chief Operating Officer	2015	$ 314,246	$ 72,000	$ 345,138		$ 731,384

(1) Represents our matching contributions paid to our 401(k) plan on behalf of Mr. Armstrong ($13,000), an allowance for personal automobile usage ($12,000), the incremental cost to the Company of Mr. Armstrong's personal use of our corporate aircraft ($20,640), and an allowance for club membership dues ($14,572). Mr. Armstrong's personal use of the corporate aircraft has been valued based on the incremental costs to us for the personal use of our aircraft. Incremental costs for personal use consist of the variable costs incurred by us to operate the aircraft for such use, including fuel costs; crew expenses, including travel, hotels and meals; in-flight catering; landing, parking and handling fees; communications expenses; certain trip-related maintenance; and other trip-related variable costs. In addition, if the aircraft flies empty before picking up or dropping off a passenger flying for personal reasons, this "deadhead" segment is included in the incremental cost of the personal use. Incremental costs do not include fixed or non-variable costs that would be incurred whether or not there was any personal use of the aircraft, such as crew salaries and benefits, insurance costs, aircraft purchase costs, depreciation and scheduled maintenance. Travel by Mr. Armstrong's spouse is generally considered personal use and is subject to taxation and disclosure.

(2) Represents our matching contributions paid to our 401(k) plan on behalf of Mr. Wilson ($13,000), an allowance for personal automobile usage ($12,000), and an allowance for club membership dues ($10,215).

(3) Represents overriding royalties paid to Mr. Allen ($209,165) (see "—Overriding Royalty Agreement" for a description of Mr. Allen's agreement with us regarding the payment of overriding royalties), our matching contributions paid to our 401(k) plan on behalf of Mr. Allen ($13,000), and an allowance for personal automobile usage ($12,000).

(4) By letter dated March 29, 2017, Mr. Allen informed the Company of his intention to retire effective June 1, 2017.

Elements of Compensation

Compensation Program

Our compensation committee continues to consider informally the executive compensation data of certain publicly traded coal companies. The compensation committee uses peer group data as a point of reference for comparative purposes, but it is not the determinative factor for our named executive officers' compensation. The compensation committee exercises discretion in determining the nature and extent of the use of comparative pay data. We did not utilize a compensation consultant in 2016. The compensation committee considered internal pay equity when making compensation decisions for executive officers, excluding any overriding royalties that may be due to executive officers. See "—Overriding Royalty Agreement." However, the compensation committee does not use a fixed ratio or formula when comparing compensation among executive officers.

The compensation program consists primarily of base salary and annual bonus. The base salary for each of our named executive officers is set forth in his employment agreement and is subject to adjustment annually as determined by the compensation committee. See "—Employment Agreements." The base salary is intended to provide a degree of financial certainty and stability, to recognize competitive market conditions and to reward individual performance through periodic increases. Base salary levels are based on the executive officer's role and responsibilities, the position's complexity and its importance to us in relation to other executive positions and the officer's experience, tenure, unique skills, past performance and future potential with the Company. Base salary increases are made at the compensation committee's discretion after a review of the executive officer's performance and the relevant market data. While the compensation committee uses market data as a point of reference for comparative purposes, it will determine the nature and amount of executive officer compensation in its sole discretion.

Executive officers' target bonus percentage amounts are based on a multiple of each executive's base salary. The annual bonus target percentage is recommended by the President and Chief Executive Officer and approved by the compensation committee, typically in January of each year. Although the individual performance component is discretionary at the sole determination of the compensation committee, with respect to the executive officers other than himself, our President and Chief Executive Officer provides his recommendations for these amounts to the compensation committee for its consideration.

Annual bonuses are intended to: (i) motivate executive officers to achieve key annual goals and position the Company for long-term success, (ii) provide compensation for performance based on the executive's achievement of strategic goals and objectives, on both an individual and a Company-wide level and (iii) retain and attract executive talent. In setting the target bonus for each executive officer, consideration is given to the target bonus set forth in the respective officer's employment agreement, if any, subject to adjustment by the compensation committee. Bonuses are typically based on financial performance goals related to our achievement of a pre-determined Adjusted EBITDA level, personal performance goals, and for Mr. Allen, the achievement of certain safety goals. However, the compensation committee has the discretion to consider other factors when the market warrants.

The compensation committee also has the authority to grant discretionary-based awards or adjust the bonus set forth above downward for one or a group of employees based on criteria set at the compensation committee's discretion.

As a result of the declining market conditions, our overall performance during 2016 and 2015, and the actions that management took to allow us to sustain our financial strength, the compensation committee unanimously voted to use its discretion as allowed under our compensation program and awarded certain of our key employees, including certain named executive officers, solely a discretionary bonus for 2016 and 2015. The compensation committee determined that such discretionary bonus was to be made on an individual basis based on the recommendation made by the President and Chief Executive Officer.

Other Executive Benefits

Our named executive officers are eligible for the following benefits on the same basis as other eligible employees:

- Health insurance;
- Vacation, personal holidays and sick time;
- Life insurance and supplemental life insurance;
- Short-term and long-term disability; and
- 401(k) plan with matching contributions.

In addition, we provide our named executive officers with an annual car allowance and a payment equal to the group term life insurance premium paid on each named executive officer's behalf. Also, we provide Messrs. Armstrong and Wilson with an allowance for club membership dues. The Company aircraft may occasionally be used by executive officers for personal travel.

Employment Agreements

Allen Employment Agreement

Effective June 1, 2007, we entered into an employment agreement (the Allen Agreement) with Mr. Allen. The term of the Allen Agreement was three years, but the Allen Agreement shall be automatically renewed for additional one-year terms until such time, if any, as we or the executive gives written notice to the other party that such automatic extension shall cease. Such notice must be given at least 60 days prior to the expiration of the then current term. Effective January 1, 2015, Mr. Allen's annual base salary was increased to $363,000. Effective September 1, 2015, Mr. Allen's annual base salary was decreased to $200,000.

The Allen Agreement contains non-competition and non-solicitation provisions that endure for a period of 12 months following the executive's termination of employment with us.

In addition, pursuant to the Allen Agreement and the related overriding royalty agreement, as amended, between Mr. Allen and us, Mr. Allen receives an overriding royalty equal to $0.05 per ton sold by us from certain reserves described in that agreement. See "—Overriding Royalty Agreement."

Pursuant to the Allen Agreement, we may terminate the agreement at any time for cause, which is defined as: (i) the executive's failure substantially to perform his duties under the agreement in a manner satisfactory to the board, (ii) the executive has engaged in gross misconduct, dishonest, disloyal, illegal or unethical conduct, or any other conduct which has or could reasonably have a detrimental impact on our company or its reputation, (iii) the executive has acted in a dishonest or disloyal manner, or breached any fiduciary duty to our company that, in either case, results or was intended to result in personal

profit to the executive at the expense of our company or any of its customers, (iv) the executive has been convicted of or pleads guilty or no contest to any felony, (v) the executive has one or more physical or mental impairments which have substantially impaired his ability to perform the essential functions of his job, (vi) the executive's death, (vii) any breach by the executive of certain obligations under the agreement or (viii) resignation by the executive under circumstances where a termination for "cause" was impending or could have reasonably been foreseen.

We also may terminate the Allen Agreement without cause. In the event of such termination without cause, the executive shall be entitled to receive (i) the executive's base salary for 12 months following termination and (ii) health insurance premiums for 12 months. In addition, the overriding royalty will run with the land per the provisions of the overriding royalty agreement. See "—Overriding Royalty Agreement."

Under the Allen Agreement, the executive may resign for good reason, which is defined as a material demotion or reduction in the executive's duties. In the event of a resignation for good reason, the executive shall be entitled to receive (i) the executive's base salary for 12 months following termination and (ii) health insurance premiums for 12 months. In addition, the respective overriding royalty will run with the land per the provisions of the overriding royalty agreement. See "—Overriding Royalty Agreement."

In the event of a termination of the executive's employment, other than for cause, within 12 months of a change in control, the executive shall be entitled to receive health insurance premiums for 12 months. In addition, we will pay, promptly following such termination, a lump sum payment equal to one times the executive's annual base salary, plus any accrued and unpaid overriding royalty.

By letter dated March 29, 2017, Mr. Allen informed the Company of his intention to retire effective June 1, 2017. In connection with his retirement, the Allen Agreement will terminate effective June 1, 2017.

Armstrong and Wilson Employment Agreements

Effective October 1, 2011, we entered into an employment agreement with each of Messrs. Armstrong and Wilson (together, the Armstrong and Wilson Agreements). Each of Mr. Wilson's and Mr. Armstrong's employment agreements was amended effective May 18, 2015 in connection with their changes in positions, as noted below, and further amended effective as of April 22, 2016 to provide for changes in compensation upon termination of employment. The term of each of the Armstrong and Wilson Agreements was three years, and each shall automatically renew for successive one-year terms unless either party gives the other a notice of non-renewal at least 90 days before the end of the then current term. On May 12, 2015, the board of directors appointed Mr. Wilson as President and Chief Executive Officer of the Company, adjusting his salary to $450,000 effective May 18, 2015. Mr. Armstrong remained in the position of Executive Chairman of the Board and his salary was adjusted to $380,000 effective May 18, 2015. Effective January 1, 2016, Mr. Armstrong's annual base salary was decreased to $300,000.

Pursuant to the Armstrong and Wilson Agreements, we may terminate Mr. Armstrong and Mr. Wilson at any time without cause (as defined below), and each Mr. Armstrong and Mr. Wilson may terminate his own employment at any time for good reason (as defined below). In the event of a termination without cause, failure by us to renew the agreement or termination by the executive for good reason, (i) we will continue to pay the executive's base salary and provide his other benefits (including automobile allowance, vacation and health insurance) for 24 months and (ii) the executive shall also be entitled to a bonus for that year equal to 100% of his base salary (irrespective of whether performance objectives have been achieved). In addition, (a) we will provide the executive with outplacement services and (b) the executive shall be entitled to a contribution under our retirement benefit plan for that fiscal year equal to the greater of (x) the amount that would have been contributed for that fiscal year determined in accordance with past practice or (y) the highest amount contributed by us on behalf of the executive for any of the three prior fiscal years.

For this purpose, cause means: (i) the executive's willful and continued failure substantially to perform his duties (other than as a result of sickness, injury or other physical or mental incapacity or as a result of termination by the executive for good reason); (ii) willful misconduct by the executive in the performance of his duties that is demonstrably and materially injurious to our company or any affiliated company; (iii) the executive's conviction of (or plea of nolo contendere to) a financial-related felony or other similarly material crime; or (iv) any material violation of the respective agreement by the executive.

For this purpose, good reason means the occurrence of any of the following: (i) the authority, duties or responsibilities of the executive are significantly and materially reduced; (ii) the annual base salary is materially reduced (except if such reduction occurs prior to a change in control and is part of an across-the-board reduction applicable to all senior level executives); (iii) the

executive is required to change his regular work location to a location that is more than 75 miles from his regular work location prior to such change; or (iv) any other action or inaction that constitutes a material breach by us of the agreement.

Pursuant to the Armstrong and Wilson Agreements, in the event that: (i) we terminate the executive's employment without cause in anticipation of, or pursuant to a notice of termination delivered to the executive within 24 months after, a change in control; (ii) the executive terminates his employment for good reason pursuant to a notice of termination delivered to us in anticipation of, or within 24 months after, a change in control; or (iii) we fail to renew the agreement in anticipation of, or within 24 months after, a change in control: (a) we shall pay to the executive, within 30 days following the executive's separation from service, a lump-sum cash amount equal to: (x) two times the sum of (A) his salary then in effect and (B) 75% of his then current salary; plus (y) a bonus for the then current fiscal year equal to 100% of his salary (irrespective of whether performance objectives have been achieved); plus (z) if such notice is given within the first 12 months after the date of a change in control, then, the salary the executive should have been paid from the date of termination through the end of such 12-month period; and (b) during the portion, if any, of the 24-month period commencing on the date of the executive's separation from service that the executive is eligible to elect and elects to continue coverage for himself and his eligible dependents under our health plan pursuant to COBRA or a similar state law, we shall reimburse the executive for the difference between the amount the executive pays to effect and continue such coverage and the employee contribution amount that our active senior executive employees pay for the same or similar coverage.

The Armstrong and Wilson Agreements contain non-competition provisions that continue for 18 months following the executive's termination and non-solicitation provisions that endure for a period of 24 months following the executive's termination.

Overriding Royalty Agreement

On December 3, 2008, we entered into an amended and restated overriding royalty agreement with Mr. Allen pursuant to which we agreed to pay Mr. Allen a royalty of $0.05 per ton of all coal thereafter mined or extracted and subsequently sold from certain of our reserves. The term of the royalty began on February 9, 2007, and is set to continue until the later of: (i) February 9, 2027, or (ii) such time as all of the mineable and saleable coal from the subject properties has been mined. The agreement also states that the overriding royalty shall constitute an independent and enforceable obligation that shall run with the land and shall be binding on us, our respective assigns and successors, and any subsequent owner of the subject properties.

Outstanding Equity Awards at 2016 Fiscal Year-End

There were no outstanding option and stock awards held by the named executive officers as of December 31, 2016.

Amended and Restated 2011 Long-Term Incentive Plan

Our board of directors adopted the 2011 Long-Term Incentive Plan during October 2011 and the Amended and Restated 2011 Long-Term Incentive Plan on February 10, 2015 (collectively, the LTIP). The LTIP will terminate upon the earlier of the adoption of a board resolution terminating the LTIP or ten years from its effective date. The LTIP provides for the granting of stock options, stock appreciation rights, restricted stock, restricted stock units, performance grants and other equity-based incentive awards to employees and directors who contribute significantly to our strategic and long-term performance objectives and growth. The maximum aggregate number of shares of common stock available for issuance under the LTIP is 10% of our authorized shares of common stock. No awards were made to the named executive officers or directors under the LTIP in 2016.

The compensation committee has the authority to administer the LTIP and may determine the type, number and size of the awards, the recipients of awards and the terms and conditions applicable to awards made under the LTIP. The compensation committee may also generally amend the terms and conditions of awards, subject to certain restrictions. Except with respect to restricted stock awards and unless otherwise determined by the compensation committee in its discretion, the recipient of an award has no rights as a stockholder until he or she receives a stock certificate or has his or her ownership entered into the books of the Company. The following is a brief summary of the types of awards available for issuance under the LTIP:

Stock Options

The compensation committee may grant non-qualified and incentive stock options under the LTIP, provided that incentive stock options shall be granted to employees only. The exercise price of stock options must be no less than the fair market value of the common stock on the date of grant and expire ten years after the date of grant. The exercise price of incentive stock options granted to holders of at least 10% of the Company's stock must be no less than 110% of such fair market value, and incentive stock options expire five years from the date of grant.

Stock Appreciation Rights

An award of a stock appreciation right entitles the recipient to receive, without payment, the number of shares of common stock having an aggregate value equal to the excess of the fair market value of one share of common stock at the time of exercise over the exercise price, times the number of shares of common stock subject to the award. Stock appreciation rights shall have an exercise price no less than the fair market value of the common stock on the date of grant.

Restricted Stock and Restricted Stock Units

In addition to other terms and conditions applicable to restricted stock and restricted stock unit awards, the compensation committee shall establish the restricted period applicable to such awards. The awards shall vest in one or more increments during the restricted period. Subject to the committee's discretion, recipients of such awards shall have voting, dividend and other stockholder rights with respect to the awards from the date of grant.

Performance Grants

Performance grants shall consist of a right that is (i) denominated in cash, common stock or any other form of award issuable under the LTIP, (ii) valued in accordance with the achievement of certain performance goals applicable to performance periods as the compensation committee may establish and (iii) payable at such time and in such form as the compensation committee shall determine. The compensation committee may reduce the amount of any performance grant in its discretion if it believes a reduction is necessary based on the recipient's performance, comparisons with compensation received by similarly-situated recipients within the industry, the Company's financial results, or any other factors deemed relevant.

Other Share-Based Awards

Other share-based awards may consist of any other right payable in, valued by or otherwise related to common stock. The awards shall vest in one or more increments during a service period.

Compensation of Directors

Each of our independent directors receives (i) an annual cash retainer of $50,000, and (ii) $1,500 per meeting of the board of directors attended by such director ($500 in the case of telephonic participation). Our compensation committee reviews and makes recommendations to the board regarding compensation of directors, including equity-based plans. We reimburse our non-employee directors for reasonable travel expenses incurred in attending board and committee meetings. Our non-employee directors also participate in the LTIP. To date, each of Messrs. Beard, Crain, Ford and Walker have been granted 10,000 shares of restricted stock of the Company under the LTIP. These shares were granted to each of the non-employee directors on February 10, 2015, and vested on February 9, 2016. Prior to the vesting date of the restricted stock grants, Mr. Beard voluntarily forfeited his grant.

The following table discloses compensation paid for the fiscal year ended December 31, 2016 to our independent directors for serving as members of the Board.

2016 Director Compensation Table

Name	Fees Earned or Paid in Cash	Total
Anson M. Beard, Jr.	$ 56,000	$ 56,000
James C. Crain	$ 56,000	$ 56,000
Richard F. Ford	$ 56,000	$ 56,000
Greg A. Walker	$ 55,000	$ 55,000

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The following table shows the amount of our common stock beneficially owned as of March 30, 2017 by: (i) each person who is known by us to own beneficially more than 5% of our common stock, (ii) each member of the board of directors, (iii) each of the named executive officers, and (iv) all members of the board of directors and the executive officers, as a group. The percentage of shares beneficially owned shown in the table is based upon 21,883,224 shares of common stock outstanding as of March 30, 2017.

A person is a "beneficial owner" of a security if that person has or shares voting or investment power over the security or if he or she has the right to acquire beneficial ownership within 60 days. Unless otherwise noted, these persons, to our knowledge, have sole voting and investment power over the shares listed. The following table includes equity awards granted to our directors and executive officers on a discretionary basis. Except as otherwise noted, the principal address for the stockholders listed below is c/o Armstrong Energy, Inc., 7733 Forsyth Boulevard, Suite 1625, St. Louis, Missouri 63105.

	Shares Beneficially Owned(1)	
	Number	Percent
J. Hord Armstrong, III (2)	148,201	*
Martin D. Wilson (3)	124,743	*
Kenneth E. Allen	12,000	*
Jeffrey F. Winnick	5,434	*
Anson M. Beard, Jr.	—	—
James C. Crain	10,000	*
Richard F. Ford	10,000	*
Greg A. Walker	10,000	*
All directors and executive officers as a group (eight persons)	320,378	1.46%
Yorktown VII Associates LLC(4)(5)	11,562,500	52.84%
Yorktown VIII Associates LLC(4)(6)	6,012,500	27.48%
Yorktown IX Associates LLC(4)(7)	2,775,000	12.68%

* Less than 1%.

(1) Does not reflect any fractional shares beneficially owned.

(2) Includes 148,201 shares of common stock held of record by the John Hord Armstrong, III Trust dated June 13, 1994, for which Mr. Armstrong, as trustee, maintains sole voting and investment authority.

(3) Includes 124,743 shares of common stock held of record by the Martin D. & Carole J. Wilson Living Trust dated September 7, 2013, for which Mr. Wilson, as trustee, maintains sole voting and investment authority.

(4) The address of this beneficial owner is 410 Park Avenue, 19th Floor, New York, New York 10022.

(5) These shares are held of record by Yorktown Energy Partners VII, L.P. Yorktown VII Company LP is the sole general partner of Yorktown Energy Partners VII, L.P. Yorktown VII Associates LLC is the sole general partner of Yorktown VII Company LP. As a result, Yorktown VII Associates LLC may be deemed to have the power to vote or direct the vote or to dispose or direct the disposition of the shares owned by Yorktown Energy Partners VII, L.P. Yorktown VII Company LP and Yorktown VII Associates LLC disclaim beneficial ownership of the securities owned by Yorktown Energy Partners VII, L.P. in excess of their pecuniary interests therein.

(6) These shares are held of record by Yorktown Energy Partners VIII, L.P. Yorktown VIII Company LP is the sole general partner of Yorktown Energy Partners VIII, L.P. Yorktown VIII Associates LLC is the sole general partner of Yorktown VIII Company LP. As a result, Yorktown VIII Associates LLC may be deemed to have the power to vote or direct the vote or to dispose or direct the disposition of the shares owned by Yorktown Energy Partners VIII, L.P. Yorktown VIII Company LP and Yorktown VIII Associates LLC disclaim beneficial ownership of the securities owned by Yorktown Energy Partners VIII, L.P. in excess of their pecuniary interests therein.

(7) These shares are held of record by Yorktown Energy Partners IX, L.P. Yorktown IX Company LP is the sole general partner of Yorktown Energy Partners IX, L.P. Yorktown IX Associates LLC is the sole general partner of Yorktown IX Company LP. As a result, Yorktown IX Associates LLC may be deemed to have the power to vote or direct the vote or to dispose or direct the disposition of the shares owned by Yorktown Energy Partners IX, L.P. Yorktown IX Company LP and Yorktown IX Associates LLC disclaim beneficial ownership of the securities owned by Yorktown Energy Partners IX, L.P. in excess of their pecuniary interests therein.

Item 13. Certain Relationships and Related-Party Transactions, and Director Independence

Policies and Procedures for Related-Party Transactions

The conflicts committee must review and approve all transactions between Armstrong Energy and any related person that are required to be disclosed pursuant to Item 404 of Regulation S-K. "Related person" and "transaction" shall have the meanings given to such terms in Item 404 of Regulation S-K, as amended from time to time. In determining whether to approve or ratify a particular transaction, the conflicts committee will take into account any factors it deems relevant.

For further information regarding our related-party transactions, see Note 13, "Related-Party Transactions," to our audited consolidated financial statements included in Item 8 — "Financial Statements and Supplementary Data."

Director Independence

Although our board members are not subject to the independence standards of The NASDAQ Stock Market LLC (NASDAQ), we use NASDAQ's independence standards for purposes of determining our directors' independence. Applying these standards, a majority of our board members are independent. The board has determined that each of Messrs. Beard, Crain, Ford and Walker is an independent director pursuant to the requirements of NASDAQ. In addition, each of our audit and compensation committee members satisfies NASDAQ's additional conditions for independence for audit and compensation committee members.

Item 14. Principal Accountant Fees and Services

The following table sets forth the amount of audit fees, tax fees, audit-related fees and all other fees billed or expected to be billed by Ernst & Young LLP, our independent registered public accounting firm for the years ended December 31, 2016 and 2015 (in thousands):

	2016	2015
Audit fees (1)	$ 402	$ 345
Tax fees (2)	75	113
Audit related fees	—	—
All other fees	—	—
Total fees	$ 477	$ 458

(1) Includes fees associated with the annual audit of our consolidated financial statements, including quarterly review procedures, and the issuance of their consent to include their audit opinion in registration statements filed with the SEC.
(2) Includes fees associated with federal and state tax compliance and consulting services.

Pre-Approval Policies and Procedures

The audit committee has adopted a policy that requires advance approval of all audit, audit-related, tax and other services performed by the Company's independent registered public accounting firm. All of the fees listed above were pre-approved in accordance with this policy. The policy provides for pre-approval by the audit committee of specifically defined audit and permitted non-audit services. Unless the specific service has been previously pre-approved with respect to that year, the audit committee must approve the permitted service before the Company's independent registered public accounting firm is engaged to perform it. The audit committee has delegated to its Chair the authority to approve permitted services, provided that he reports any decisions to the audit committee at its next scheduled meeting. The audit committee, after review and discussion with Ernst & Young LLP of the Company's pre-approval policies and procedures, determined that the provision of these services in accordance with such policies and procedures was compatible with maintaining the firm's independence.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) The following documents are filed as part of this Annual Report.

1. Financial Statements

   The consolidated financial statements of Armstrong Energy, Inc. and subsidiaries (formerly Armstrong Land Company, LLC and subsidiaries), together with the report thereon of our independent registered public accounting firm, are included on pages F-1 through F-37 of this Annual Report on Form 10-K.

2. Financial Statement Schedules

   All schedules have been omitted because they are not required, not applicable, not present in amounts sufficient to require submission of the schedule, or the required information is otherwise included.

3. Exhibits

   The exhibits required to be filed as part of this annual report on Form 10-K are listed in the attached Index to Exhibits.

(b) The exhibits filed with this annual report on Form 10-K are listed in the attached Index to Exhibits.

(c) None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on March 31, 2017.

ARMSTRONG ENERGY, INC.

By: /s/ Martin D. Wilson
Martin D. Wilson
President and Chief Executive Officer
(Principal Executive Officer)

By: /s/ Jeffrey F. Winnick
Jeffrey F. Winnick
Vice President
and Chief Financial Officer
(Principal Financial and Accounting Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 31, 2017.

Signature	Title
/s/ J. Hord Armstrong, III J. Hord Armstrong, III	Executive Chairman
/s/ Martin D. Wilson Martin D. Wilson	President, Chief Executive Officer and Director *(Principal Executive Officer)*
/s/ Jeffrey F. Winnick Jeffrey F. Winnick	Vice President and Chief Financial Officer *(Principal Financial and Accounting Officer)*
/s/ Anson M. Beard, Jr. Anson M. Beard, Jr.	Director
/s/ James C. Crain James C. Crain	Director
/s/ Richard F. Ford Richard F. Ford	Director
/s/ Greg A. Walker Greg A. Walker	Director

INDEX TO EXHIBITS

Exhibit Number	Description	Incorporated by Reference				Filed or Furnished Herewith
		Form	File Number	Exhibit	Filing Date	
3.1	Certificate of Conversion of Armstrong Land Company, LLC to Armstrong Land Company, Inc., effective as of October 1, 2011.	S-4	333-191182	3.1	09/16/13	
3.2	Certificate of Incorporation of Armstrong Land Company, Inc., effective as of October 1, 2011.	S-4	333-191182	3.2	09/16/13	
3.3	Certificate of Amendment to Certificate of Incorporation of Armstrong Land Company, Inc., effective as of October 5, 2011.	S-4	333-191182	3.3	09/16/13	
3.4	Amended and Restated Certificate of Designations of Series A Convertible Preferred Stock of Armstrong Energy, Inc., effective as of March 6, 2012.	S-4	333-191182	3.4	09/16/13	
3.5	Bylaws of Armstrong Energy, Inc., effective as of October 3, 2011.	S-4	333-191182	3.5	09/16/13	
4.1	Registration Rights Agreement dated April 11, 2012 by and among Armstrong Energy, Inc. and J. Hord Armstrong, III, Martin D. Wilson, Yorktown Energy Partners VI, L.P., Yorktown Energy Partners VII, L.P., Yorktown Energy Partners VIII, L.P., Yorktown Energy Partners IX, L.P., LucyB Trust (February 26, 2007), Lorenzo Weisman/Danielle Weisman Joint Ownership with Right of Survivorship, James H. Brandi, Brim Family 2004 Trust, Franklin W. Hobbs IV, Hutchinson Brothers, LLC and John H. Stites, III.	S-4	333-191182	4.6	09/16/13	
4.2	Indenture dated as of December 21, 2012 among Armstrong Energy Inc. and Armstrong Air, LLC, Armstrong Coal Company, Inc., Armstrong Energy Holdings, Inc., Western Diamond LLC and Western Land Company, LLC, as Guarantors, and Wells Fargo Bank, National Association, as Trustee and as Collateral Agent.	S-4	333-191182	4.7	09/16/13	
4.3	First Supplemental Indenture, dated as of September 19, 2013, among Armstrong Logistics Services, LLC, Armstrong Energy, Inc., and Wells Fargo Bank, National Association, as Trustee under the Indenture.	S-4	333-191182	4.8	09/23/13	
4.4	Registration Rights Agreement dated December 21, 2012 among Armstrong Energy, Inc. and Armstrong Air, LLC, Armstrong Coal Company, Inc., Armstrong Energy Holdings, Inc., Western Diamond LLC and Western Land Company, LLC, as Guarantors, and Stifel, Nicolaus & Company, Incorporated, as representative of the several initial purchasers.	S-4	333-191182	4.8	09/16/13	
4.5	Intercreditor Agreement dated as of December 21, 2012 by and between PNC Bank, National Association, as Agent, and Wells Fargo Bank, National Association, as Trustee, and acknowledged by Armstrong Energy, Inc., Armstrong Air LLC, Armstrong Coal Company, Inc., Armstrong Energy Holdings, Inc., Western Diamond LLC and Western Land Company LLC.	S-4	333-191182	4.9	09/16/13	
4.6	Security Agreement dated as of December 21, 2012 by and among Armstrong Air, LLC, Armstrong Coal Company, Inc., Armstrong Energy, Inc., Armstrong Energy Holdings, Inc., Western Diamond LLC and Western Land Company, LLC, as Grantors, and Wells Fargo Bank, National Association, as Collateral Agent.	S-4	333-191182	4.10	09/16/13	

Exhibit Number	Description	Incorporated by Reference				Filed or Furnished Herewith
		Form	File Number	Exhibit	Filing Date	
4.7	Joinder No. 1, dated as of September 19, 2013, to the Security Agreement, dated as of December 21, 2012, by and among Each of the Parties Listed on the Signature Pages thereto and Those Additional Entities that Thereafter Become Parties thereto and Wells Fargo Bank, National Association, as Trustee and as Collateral Agent.	S-4	333-191182	4.12	09/23/13	
4.8	Security Agreement dated as of December 21, 2012 by and among Armstrong Energy, Inc., Armstrong Coal Company, Inc., Armstrong Energy Holdings, Inc., Armstrong Air, LLC, Western Land Company, LLC and Western Diamond LLC, as Debtors, and PNC Bank, National Association, as Administrative Agent.	S-4	333-191182	4.11	09/16/13	
4.9	Second Supplemental Indenture, dated as of July 24, 2014, among Thoroughfare Mining, LLC, Armstrong Energy, Inc., and Wells Fargo Bank, National Association, as Trustee under the Indenture.	10-Q	333-191182	4.15	08/14/14	
4.10	Joinder No. 2, dated as of July 24, 2014, to the Security Agreement, dated as of December 21, 2012 (as amended, restated, supplemented, or otherwise modified from time to time), by and among Each of the Parties Listed on the Signature Pages thereto and Those Additional Entities that Thereafter Become Parties thereto and Wells Fargo Bank, National Association, as Trustee and as Collateral Agent.	10-Q	333-191182	4.16	08/14/14	
4.11	Third Supplemental Indenture, dated as of August 14, 2014, among Armstrong Energy, Inc. and Wells Fargo Bank, National Association, as Trustee under the Indenture.	10-Q	333-191182	4.17	08/14/14	
4.12	Fourth Supplemental Indenture, dated as of January 29, 2015, among Armstrong Coal Sales, LLC, Armstrong Energy, Inc., and Wells Fargo Bank, National Association, as Trustee under the Indenture.	10-K	333-191182	4.12	03/26/15	
4.13	Joinder No. 3, dated as of January 29, 2015, to the Security Agreement, dated as of December 21, 2012 (as amended, restated, supplemented, or otherwise modified from time to time), by and among Each of the Parties Listed on the Signature Pages thereto and Those Additional Entities that Thereafter Become Parties thereto and Wells Fargo Bank, National Association, as Trustee and as Collateral Agent.	10-K	333-191182	4.13	03/26/15	
10.1	Credit Agreement dated as of December 21, 2012 by and among Armstrong Energy, Inc., as Borrower, Armstrong Coal Company, Inc., Armstrong Energy Holdings, Inc., Armstrong Air, LLC, Western Land Company, LLC and Western Diamond LLC, as Guarantors, the Lenders, Stifel Bank & Trust, as Agent, and PNC Bank, National Association, as Administrative Agent.	S-4	333-191182	10.1	09/16/13	
10.2	Coal Supply Agreement by and between Louisville Gas and Electric Company and Kentucky Utilities Company, as Buyer, and Armstrong Coal Company, Inc., as Seller, effective as of January 1, 2008.	S-4	333-191182	10.20	09/16/13	
10.3	Amendment No. 1 to Coal Supply Agreement by and between Louisville Gas and Electric Company and Kentucky Utilities Company, as Buyer, and Armstrong Coal Company, Inc., as Seller, effective as of July 1, 2008.	S-4	333-191182	10.21	09/16/13	

Exhibit Number	Description	Incorporated by Reference				Filed or Furnished Herewith
		Form	File Number	Exhibit	Filing Date	
10.4	Letter Agreement by and between Louisville Gas and Electric Company and Kentucky Utilities Company, as Buyer, and Armstrong Coal Company, Inc., as Seller, dated December 8, 2008.	S-4	333-191182	10.22	09/16/13	
10.5	Letter Agreement by and between Louisville Gas and Electric Company and Kentucky Utilities Company, as Buyer, and Armstrong Coal Company, Inc., as Seller, dated April 1, 2009.	S-4	333-191182	10.23	09/16/13	
10.6	Amendment No. 2 to Coal Supply Agreement by and between Louisville Gas and Electric Company and Kentucky Utilities Company, as Buyer, and Armstrong Coal Company, Inc., as Seller, effective as of December 22, 2009.	S-4	333-191182	10.24	09/16/13	
10.7	Settlement Agreement and Release by and between Louisville Gas and Electric Company and Kentucky Utilities Company and Armstrong Coal Company, Inc., dated as of December 22, 2009.	S-4	333-191182	10.25	09/16/13	
10.8	Coal Supply Agreement by and between Louisville Gas and Electric Company and Kentucky Utilities Company, as Buyer, and Armstrong Coal Company, Inc., as Seller, dated January 1, 2013.	S-4	333-191182	10.30	09/16/13	
10.9†	Employment Agreement by and between Armstrong Energy, Inc. and Jeffrey F. Winnick, dated as of September 1, 2015.	10-Q	333-191182	10.1	11/12/15	
10.10†	First Amendment to Employment Agreement by and between Armstrong Energy, Inc. and Jeffrey F. Winnick, dated as of April 22, 2016.	10-Q	333-191182	10.5	05/15/16	
10.11†	Second Amendment to Employment Agreement by and between Armstrong Energy, Inc. and Jeffrey F. Winnick, dated as of March 17, 2017					X
10.12†	Employment Agreement by and between Armstrong Energy, Inc. and J. Hord Armstrong, III, dated as of October 1, 2011.	S-4	333-191182	10.32	09/16/13	
10.13†	First Amendment to Employment Agreement by and between Armstrong Energy, Inc. and J. Hord Armstrong, III, dated as of May 18, 2015.	10-Q	333-191182	10.2	05/15/16	
10.14†	Second Amendment to Employment Agreement by and between Armstrong Energy, Inc. and J. Hord Armstrong, III, dated as of April 22, 2016.	10-Q	333-191182	10.4	05/15/16	
10.15†	Employment Agreement by and between Armstrong Energy, Inc. and Martin D. Wilson, dated as of October 1, 2011.	S-4	333-191182	10.33	09/16/13	
10.16†	First Amendment to Employment Agreement by and between Armstrong Energy, Inc. and Martin D. Wilson, dated as of May 18, 2015.	10-Q	333-191182	10.1	05/15/16	
10.17†	Second Amendment to Employment Agreement by and between Armstrong Energy, Inc. and Martin D. Wilson, dated as of April 22, 2016.	10-Q	333-191182	10.3	05/15/16	
10.18†	Employment Agreement by and between Armstrong Coal Co. and Kenneth E. Allen, dated as of June 1, 2007.	S-4	333-191182	10.34	09/16/13	
10.19†	Form of Director Indemnification Agreement.	S-4	333-191182	10.37	09/16/13	

Exhibit Number	Description	Incorporated by Reference				Filed or Furnished Herewith
		Form	File Number	Exhibit	Filing Date	
10.20†	Amended and Restated Armstrong Energy, Inc. 2011 Long-Term Incentive Plan	10-K	333-191182	10.30	03/26/15	
10.21	Amended Overriding Royalty Agreement by and among Western Land Company, LLC, Western Diamond, LLC, Ceralvo Holdings, LLC, Armstrong Mining, Inc., Armstrong Coal Company, Inc., Armstrong Land Company, LLC and Kenneth E. Allen, dated as of December 3, 2008.	S-4	333-191182	10.39	09/16/13	
10.22	Administrative Services Agreement by and between Armstrong Energy, Inc., Armstrong Resource Partners, L.P. and Elk Creek GP, LLC, effective as of January 1, 2011.	S-4	333-191182	10.41	09/16/13	
10.23	Coal Mining Lease and Sublease Agreement between Armstrong Coal Company, Inc. and Ceralvo Holdings, LLC, dated February 9, 2011 (Elk Creek).	S-4	333-191182	10.42	09/16/13	
10.24	Coal Mining Lease between Alcoa Fuels, Inc. and Armstrong Coal Company, Inc., dated as of October 27, 2010.	S-4	333-191182	10.46	09/16/13	
10.25	Coal Mining Lease between Alcoa Fuels, Inc. and Armstrong Coal Company, Inc., dated as of June 1, 2016.	10-Q	333-191182	10.6	08/11/16	
10.26	Asset Purchase Agreement, dated as of December 29, 2011, by and between Cyprus Creek Land Resources, LLC and Armstrong Coal Company, Inc.	S-4	333-191182	10.47	09/16/13	
10.27	Contract to Sell and Lease Real Estate between Midwest Coal Reserves of Kentucky, LLC and Armstrong Coal Company, Inc. dated December 25, 2011.	S-4	333-191182	10.49	09/16/13	
10.28	Share Exchange Agreement dated as of December 12, 2012 by and between Armstrong Energy, Inc. and Yorktown Energy Partners IX, L.P.	S-4	333-191182	10.52	09/16/13	
10.29	Guarantor Joinder and Assumption Agreement made as of September 19, 2013 by Armstrong Logistics Services, LLC.	S-4	333-191182	4.14	09/23/13	
10.30	First Amended and Restated Royalty Deferment and Option Agreement by and between Armstrong Coal Company, Inc., Thoroughfare Mining, LLC, Western Diamond LLC, Western Land Company, LLC and Thoroughbred Resources, L.P., Western Mineral Development, LLC, and Ceralvo Holdings, LLC, effective August 14, 2014.	10-Q	333-191182	10.54	08/14/14	
10.31	First Amendment to Credit Agreement dated as of August 14, 2014 by and among Armstrong Energy, Inc., as Borrower, Armstrong Coal Company, Inc., Armstrong Energy Holdings, Inc., Armstrong Air, LLC, Western Land Company, LLC, Western Diamond LLC, Armstrong Logistics Services, LLC, and Thoroughfare Mining, LLC, as Guarantors, the Lenders, Stifil Bank & Trust, as Syndication Agent, PNC Bank, National Association, as Administrative Agent, and US Bank, National Association.	10-Q	333-191182	10.55	08/14/14	
10.32	Guarantor Joinder and Assumption Agreement made as of July 24, 2014 by Thoroughfare Mining, LLC.	10-Q	333-191182	10.56	08/14/14	
10.33	Guarantor Joinder and Assumption Agreement made as of January 29, 2015 by Armstrong Coal Sales, LLC.	10-K	333-191182	10.42	03/26/15	

Exhibit Number	Description	Incorporated by Reference				Filed or Furnished Herewith
		Form	File Number	Exhibit	Filing Date	
10.34	Settlement Agreement and Release of Claims dated as of March 29, 2017 by and between Armstrong Energy, Inc., Armstrong Coal Company, Inc., Elk Creek GP, LLC, Thoroughfare Mining, LLC, Western Diamond LLC, and Western Land Company, LLC; and Thoroughbred Holdings GP, LLC, Thoroughbred Resources, L.P., Western Mineral Development, LLC, and Ceralvo Holdings, LLC.					X
21.1	List of Subsidiaries.					X
23.1	Consent of Weir International, Inc.					X
31.1	Certification of Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
31.2	Certification of Principal Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
32.1#	Certification of Principal Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					X
32.2#	Certification of Principal Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					X
95.1	Federal Mine Safety and Health Act Information.					X
99.1	Audit Committee Charter.	S-4	333-191182	99.1	09/16/13	
99.2	Compensation Committee Charter	S-4	333-191182	99.2	09/16/13	
99.3	Nominating and Corporate Governance Committee Charter					X
101.INS	XBRL Instance Document					X
101.SCH	XBRL Taxonomy Extension Scheme Document					X
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document					X
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document					X
101.LAB	XBRL Taxonomy Extension Label Linkbase Document					X
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document					X

† Indicates a management contract or compensatory plan or arrangement.

This certification is deemed not "filed" for purposes of Section 18 of the Exchange Act or otherwise subject to the liability of that section, nor shall it be deemed incorporated by reference into any filing under the Securities Act or the Exchange Act.

INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of

Armstrong Energy, Inc. and Subsidiaries

We have audited the accompanying consolidated balance sheets of Armstrong Energy, Inc. and Subsidiaries (the Company) as of December 31, 2016 and 2015, and the related consolidated statements of operations, comprehensive income (loss), stockholders' equity (deficit) and cash flows for each of the three years in the period ended December 31, 2016. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of the Company at December 31, 2016 and 2015, and the consolidated results of its operations and its cash flows for the each of the three years in the period ended December 31, 2016, in conformity with U.S. generally accepted accounting principles.

The accompanying consolidated financial statements have been prepared assuming the Company will continue as a going concern. As discussed in Note 3 to the financial statements, the Company incurred a substantial loss from operations and has a net capital deficit as of and for the year ended December 31, 2016. The Company's operating plan indicates that it will continue to incur losses from operations, and generate negative cash flows from operating activities during the year ended December 31, 2017. These projections and certain liquidity risks raise substantial doubt about the Company's ability to meet its obligations as they become due within one year after the date of this report and continue as a going concern. Management's plans in regard to these matters are also described in Note 3. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

/s/ Ernst & Young LLP

St. Louis, Missouri
March 31, 2017

Armstrong Energy, Inc. and Subsidiaries
CONSOLIDATED BALANCE SHEETS
(Dollars in thousands, except per share amounts)

	December 31,	
	2016	2015
ASSETS		
Current assets:		
Cash and cash equivalents	$ 57,505	$ 67,617
Accounts receivable	13,059	14,270
Inventories	11,809	14,562
Prepaid and other assets	2,539	1,952
Total current assets	84,912	98,401
Property, plant, equipment, and mine development, net	233,766	261,398
Investments	2,794	3,525
Other non-current assets	12,683	17,387
Total assets	$ 334,155	$ 380,711
LIABILITIES AND STOCKHOLDERS' EQUITY/(DEFICIT)		
Current liabilities:		
Accounts payable	$ 16,941	$ 22,555
Accrued and other liabilities	11,837	13,045
Current portion of capital lease obligations	555	1,943
Current maturities of long-term debt	8,217	8,402
Total current liabilities	37,550	45,945
Long-term debt, less current maturities	199,040	203,508
Long-term obligation to related party	147,536	128,809
Related-party payables, net	22,557	16,413
Asset retirement obligations	14,056	13,990
Long-term portion of capital lease obligations	—	555
Other non-current liabilities	7,223	6,772
Total liabilities	427,962	415,992
Stockholders' deficit:		
Common stock, $0.01 par value, 70,000,000 shares authorized, 21,883,224 shares and 21,853,224 shares issued and outstanding as of December 31, 2016 and 2015, respectively	219	218
Preferred stock, $0.01 par value, 1,000,000 shares authorized, zero shares issued and outstanding as of December 31, 2016 and 2015, respectively	—	—
Additional paid-in-capital	238,675	238,695
Accumulated deficit	(331,164)	(272,334)
Accumulated other comprehensive loss	(1,560)	(1,883)
Armstrong Energy, Inc.'s deficit	(93,830)	(35,304)
Non-controlling interest	23	23
Total stockholders' deficit	(93,807)	(35,281)
Total liabilities and stockholders' deficit	$ 334,155	$ 380,711

See accompanying notes to consolidated financial statements.

Armstrong Energy, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF OPERATIONS
(Dollars in thousands)

	Year Ended December 31,		
	2016	**2015**	**2014**
Revenue	**$ 253,902**	$ 360,900	$ 441,833
Costs and expenses:			
Cost of coal sales, exclusive of items shown separately below	**207,630**	282,903	362,294
Production royalty to related party	**7,121**	7,879	8,269
Depreciation, depletion, and amortization	**31,040**	47,259	46,512
Asset retirement obligation expenses	**1,428**	1,966	1,624
Asset impairment and restructuring charges	**4,431**	138,679	—
Non-cash charge on settlement with Thoroughbred	**10,542**	—	—
General and administrative expenses	**13,541**	15,813	19,590
Operating (loss) income	**(21,831)**	(133,599)	3,544
Other income (expense):			
Interest expense, net	**(34,183)**	(34,685)	(33,134)
Other, net	**(2,699)**	5,486	758
Loss before income taxes	**(58,713)**	(162,798)	(28,832)
Income taxes	**(117)**	657	—
Net loss	**(58,830)**	(162,141)	(28,832)
Less: income attributable to non-controlling interest	**—**	—	—
Net loss attributable to common stockholders	**$ (58,830)**	$ (162,141)	$ (28,832)

See accompanying notes to consolidated financial statements.

Armstrong Energy, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Dollars in thousands)

	Year Ended December 31,		
	2016	**2015**	**2014**
Net loss	**$ (58,830)**	$ (162,141)	$ (28,832)
Postretirement benefit plan and other employee benefit obligations, net of tax	**323**	1,858	(3,004)
Other comprehensive income (loss)	**323**	1,858	(3,004)
Comprehensive loss	**(58,507)**	(160,283)	(31,836)
Less: comprehensive income (loss) attributable to non-controlling interests	**—**	—	—
Comprehensive loss attributable to common stockholders	**$ (58,507)**	$ (160,283)	$ (31,836)

See accompanying notes to consolidated financial statements.

Armstrong Energy, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY/(DEFICIT)
(Amounts in thousands)

	Common Stock		Preferred Stock						
	Number of Shares	Amount	Number of Shares	Amount	Additional Paid-in-Capital	Accumulated Deficit	Accumulated Other Comprehensive Loss	Non-Controlling Interest	Total Stockholders' Equity/(Deficit)
Balance at December 31, 2013	21,934	$ 219	—	$ —	$ 238,799	$ (81,361)	$ (737)	$ 23	$ 156,943
Net loss	—	—	—	—	—	(28,832)	—	—	(28,832)
Stock-based compensation	—	—	—	—	(74)	—	—	—	(74)
Postretirement benefit plan and other employee benefit obligations	—	—	—	—	—	—	(3,004)	—	(3,004)
Repurchase of employee stock relinquished for tax withholdings	(15)	—	—	—	(176)	—	—	—	(176)
Shares issued under employee plan	18	—	—	—	—	—	—	—	—
Balance at December 31, 2014	21,937	219	—	—	238,549	(110,193)	(3,741)	23	124,857
Net loss	—	—	—	—	—	(162,141)	—	—	(162,141)
Stock-based compensation	—	—	—	—	145	—	—	—	145
Postretirement benefit plan and other employee benefit obligations	—	—	—	—	—	—	1,858	—	1,858
Repurchase of employee stock relinquished for tax withholdings	(84)	(1)	—	—	1	—	—	—	—
Balance at December 31, 2015	21,853	218	—	—	238,695	(272,334)	(1,883)	23	(35,281)
Net loss	**—**	**—**	**—**	**—**	**—**	**$ (58,830)**	**—**	**—**	**(58,830)**
Stock-based compensation	**—**	**—**	**—**	**—**	**(19)**	**—**	**—**	**—**	**(19)**
Postretirement benefit plan and other employee benefit obligations	**—**	**—**	**—**	**—**	**—**	**—**	**323**	**—**	**323**
Shares issued under employee plan	**30**	**1**	**—**	**—**	**(1)**	**—**	**—**	**—**	**—**
Balance at December 31, 2016	**21,883**	**$ 219**	**—**	**$ —**	**$238,675**	**$(331,164)**	**$(1,560)**	**$23**	**$(93,807)**

See accompanying notes to consolidated financial statements.

Armstrong Energy, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in thousands)

	Year Ended December 31,		
	2016	**2015**	**2014**
Cash Flows from Operating Activities			
Net loss	**$ (58,830)**	$ (162,141)	$ (28,832)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Non-cash stock compensation (income) expense	**(19)**	145	(74)
Depreciation, depletion, and amortization	**31,040**	47,259	46,512
Amortization of debt issuance costs	**1,636**	1,538	1,197
Amortization of original issue discount	**959**	850	752
Asset retirement obligation expenses	**1,428**	1,966	1,624
Asset impairment	**4,431**	137,678	—
Income from equity affiliate	**(89)**	(153)	(150)
Loss on termination of credit facility	**403**	—	—
(Gain) loss on disposal of property, plant, and equipment	**—**	(266)	80
Non-cash charge on settlement with Thoroughbred	**10,542**	—	—
Non-cash activity with related party, net	**14,330**	16,337	14,822
Loss on partial disposal of investment in equity affiliate	**320**	—	—
Non-cash interest on long-term obligations	**(8)**	(4)	(4)
Change in working capital accounts:			
Decrease in accounts receivable	**1,210**	7,529	2,855
Decrease (increase) in inventories	**2,752**	(4,010)	2,130
(Increase) decrease in prepaid and other assets	**(587)**	1,011	707
Increase in other non-current assets	**(441)**	(752)	(2,753)
(Decrease) increase in accounts payable and accrued and other liabilities	**(6,690)**	(10,865)	187
Increase in other non-current liabilities	**623**	121	2,092
Net cash provided by operating activities	**3,010**	36,243	41,145
Cash Flows from Investing Activities			
Investment in property, plant, equipment, and mine development	**(3,029)**	(19,805)	(24,442)
Proceeds from partial disposal of investment in equity affiliate	**500**	—	—
Proceeds from disposal of property, plant, and equipment	**—**	880	5
Net cash used in investing activities	**(2,529)**	(18,925)	(24,437)
Cash Flows from Financing Activities			
Payment on capital lease obligations	**(1,943)**	(2,714)	(2,690)
Payments of long-term debt	**(8,650)**	(6,505)	(5,942)
Proceeds from sale-leaseback	**—**	—	986
Payment of financing costs and fees	**—**	—	(1,000)
Repurchase of employee stock relinquished for tax withholdings	**—**	—	(176)
Net cash used in financing activities	**(10,593)**	(9,219)	(8,822)
Net (decrease) increase in cash and cash equivalents	**(10,112)**	8,099	7,886
Cash and cash equivalents, at beginning of year	**67,617**	59,518	51,632
Cash and cash equivalents, at end of year	**$ 57,505**	$ 67,617	$ 59,518
Supplemental cash flow information:			
Cash paid for interest	$ 24,621	$ 24,244	$ 24,115
Cash paid for income taxes	340	303	—
Non-cash transactions:			
Assets acquired with long-term debt	1,697	20,205	5,410
Non-cash portion of land and reserve sale/financing with related party	16,413	18,172	8,202
Assets acquired by capital lease	—	1,428	2,256

See accompanying notes to consolidated financial statements.

Armstrong Energy, Inc. and Subsidiaries
NOTES TO AUDITED CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in thousands, except per share amounts)

1. DESCRIPTION OF BUSINESS AND ENTITY STRUCTURE

Armstrong Energy, Inc. and its subsidiaries and controlled entities (collectively, AE or the Company) commenced business on September 19, 2006 (inception), for the purpose of owning and operating coal reserves (also referred to as mineral rights) and production assets. As of December 31, 2016, all subsidiaries are majority owned. The Company is a producer of low chlorine, high sulfur thermal coal from the Illinois Basin, operating both surface and underground mines. AE, which is headquartered in St. Louis, Missouri, markets its coal primarily to electric utility companies as fuel for their steam-powered generators. As of December 31, 2016, the Company had approximately 637 employees, none of whom are under a collective bargain arrangement.

Prior to September 1, 2016, the Company's wholly-owned subsidiary, Elk Creek GP, LLC (ECGP), was the sole general partner of, and had an approximate 0.2% ownership in, Thoroughbred Resources, L.P. (Thoroughbred). The various limited partners of Thoroughbred are related parties, as the entity is majority owned by investment funds managed by Yorktown Partners LLC (Yorktown), which has a majority ownership in the Company. Effective September 1, 2016, Yorktown exercised its right under the Second Amended and Restated Agreement of Limited Partnership of Thoroughbred Resources, L.P. to remove ECGP as the general partner of Thoroughbred. The Company does not consolidate the financial results of Thoroughbred. See Note 13, "Related-Party Transactions," for further discussion.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Factors Affecting Comparability

Certain prior year amounts have been reclassified to conform to current year presentation, with no effect on the previously reported results of operations. In addition, the reclassifications were not material to the accompanying footnotes to the prior year consolidated financial statements.

Principles of Consolidation

The consolidated financial statements include the accounts of AE and its wholly and majority-owned subsidiaries. All significant intercompany balances and transactions were eliminated.

Newly Adopted Accounting Standards and Accounting Standards Not Yet Implemented

In February 2016, the Financial Accounting Standards Board (FASB) issued updated guidance regarding the accounting for leases. This update requires lessees to recognize a lease liability and a lease asset for all leases, including operating leases, with a term greater than 12 months on its balance sheet. The update also expands the required quantitative and qualitative disclosures surrounding leases. This update is effective for fiscal years beginning after December 15, 2018 and interim periods within those fiscal years, with earlier application permitted. This update will be applied using a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. The Company is currently evaluating the effect of this update on its consolidated financial statements.

In November 2015, the FASB issued guidance that eliminates the requirement to present deferred tax liabilities and assets as current and noncurrent in a classified balance sheet. Instead, entities will be required to classify all deferred tax assets and liabilities as noncurrent. The new guidance is effective for financial statements issued for annual periods beginning after December 15, 2016, and interim periods within those annual periods, with early adoption permitted. The Company adopted this standard as of December 31, 2015. While the adoption of this guidance impacted the Company's balance sheet disclosure, it did not affect the Company's results of operations or cash flows.

In April 2015, the FASB issued guidance requiring an entity to present deferred financing costs on the balance sheet as a direct deduction from the related debt liability as opposed to an asset. Amortization of the costs will continue to be reported as interest expense. In August 2015, the FASB issued an accounting standards update about the presentation and subsequent measurement of deferred financing costs associated with line-of-credit arrangements, which allows for the presentation of deferred financing costs as an asset regardless of whether or not there is an outstanding balance on the line-of-credit arrangement. The updates are effective for annual reporting periods (including interim reporting periods within those periods) beginning after December 15, 2015. The Company adopted these standards during the three months ended March 31, 2016.

Prior to its termination, the Company reported the unamortized deferred financing costs associated with its asset-based revolving credit facility dated December 21, 2012 (the 2012 Credit Facility) within other non-current assets, whereas unamortized deferred financing costs associated with the Company's 11.75% Senior Secured Notes due 2019 (the Notes) have been reclassified for all periods presented.

In February 2015, the FASB issued guidance changing the requirements and analysis required when determining the reporting entity's need to consolidate an entity, including modifying the evaluation of limited partnerships variable interest status, the presumption that a general partner should consolidate a limited partnership, and the consolidation criterion applied by a reporting entity involved with variable interest entities. The Company adopted this guidance during the first quarter of 2016, and it did not have an impact on its historical consolidation conclusions.

In August 2014, the FASB issued guidance on management's responsibility in evaluating, at each annual and interim reporting period, whether there is substantial doubt about an entity's ability to continue as a going concern and to provide related footnote disclosures. The new guidance is effective for the annual period ending after December 15, 2016, and for annual periods and interim periods thereafter with early adoption permitted. The Company adopted this standard as of December 31, 2016. See Note 3, "Liquidity and Going Concern," for a discussion of the Company's ability to continue as a going concern.

In May 2014, the FASB issued a comprehensive revenue recognition standard that will supersede nearly all existing revenue recognition guidance under U.S. generally accepted accounting principles (GAAP). The standard requires revenue to be recognized when promised goods or services are transferred to a customer in an amount that reflects the consideration expected in exchange for those goods or services. The standard permits the use of either the full retrospective or modified retrospective transition method. This guidance is effective for annual and interim reporting periods beginning after December 15, 2017, with early adoption permitted to the original effective date of December 15, 2016. The Company's primary source of revenue is from the sale of coal through both short-term and long-term contracts, primarily with utilities, whereby revenue is currently recognized when risk of loss has passed to the customer. During 2016, the Company started its initial review of contracts with customers and does not currently anticipate any material change in the timing or method of recognizing revenue from our current practice. As such, the Company does not believe this new standard will have a material impact on its results of operations, financial condition or cash flows. The Company will adopt the new standard as of January 1, 2018, utilizing the modified retrospective method.

Use of Estimates

The preparation of consolidated financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of income and loss during the reporting periods. Actual results could differ from those estimates.

Revenue

Coal sales are recognized as revenue when title and risk of loss passes to the customer. Coal sales are made to customers under the terms of supply agreements, most of which are long-term (greater than one year). Under the terms of the Company's coal supply agreements, title and risk of loss typically transfer to the customer at the mine where coal is loaded on the truck, rail, or barge. Coal sales include the freight charged to the customer on destination contracts.

Other Income (Expense), Net

Other income includes farm income, timber income, and other income from the lease of surface property. For the year ended December 31, 2016, the Company has incurred expenses related to the evaluation of certain strategic alternatives and restructuring of our capital structure totaling $2,389 (See Note 3, "Liquidity and Going Concern," for further details), which is included as a component of other, net. For the year ended December 31, 2015, other, net also includes a refund for a portion of the Kentucky sales and use taxes paid on the purchase of certain energy and energy producing fuels for the period of 2008 through 2013. The refund, including interest, totaled $4,482 and was received during the second quarter of 2015.

Cash and Cash Equivalents

Cash and cash equivalents are stated at cost, which approximates fair value. The Company considers all cash and temporary investments having an original maturity of less than three months to be cash equivalents.

Accounts and Other Receivables

Accounts receivable are recorded at the invoiced amount and do not bear interest. The Company evaluates the need for an allowance for doubtful accounts based on anticipated recovery and industry data. As of December 31, 2016 and 2015, the Company had not established an allowance for uncollectible amounts.

Inventories

Inventories consist of coal, as well as materials and supplies that are valued at the lower of cost or market. Raw coal stockpiles may be sold in their current condition or processed further prior to shipment. Cost is determined using the first-in, first-out method for materials and supplies. Coal inventory costs include labor, supplies, equipment cost, royalties, taxes, other related costs, and, where applicable, preparation plant costs. Stripping costs incurred during the production phase of the mine are considered variable production costs and are included in the cost of coal during the period the stripping costs are incurred.

Property, Plant, Equipment, and Mine Development

Property, plant, equipment, and mine development are recorded at cost. Interest costs applicable to major asset additions are capitalized during the construction period. Capitalized interest in 2016, 2015, and 2014 was $626, $1,987, and $973, respectively.

Expenditures that extend the useful lives of existing plant and equipment assets are capitalized, while normal repairs and maintenance that do not extend the useful life or increase the productivity of the asset are expensed as incurred. Plant and equipment are depreciated using the straight-line method over the useful lives of the assets, which are detailed below.

Asset Type	Life (Years)
Buildings and improvements	7-40
Mine equipment	2-10
Vehicles	3-10
Office equipment and software	3-7

Costs to acquire or construct significant new assets are capitalized and amortized using the units-of-production method over the estimated recoverable reserves that are associated with the property being benefited, when placed into service, as a part of the new asset being constructed. These costs include but are not limited to legal fees, permit and license costs, materials cost, associated labor costs, mine design, construction of access roads, shafts, slopes and main entries, and removing overburden to access reserves in a new pit. Where multiple assets are acquired for one purchase price, the cost of the purchase is allocated among the individual assets in proportion to their market value, with assistance from a third party specializing in the valuation of the purchased assets.

Mineral rights are recorded at cost as property, plant, equipment, and mine development. Amortization of mineral rights and mine development is provided by the units-of-production method over estimated total recoverable proven and probable reserves.

Costs related to locating coal deposits and evaluating the economic viability of such deposits are expensed as incurred. The Company did not incur a significant amount of these costs in 2016, 2015, or 2014. Start-up costs are expensed as incurred. Certain costs incurred to develop coal mines or to expand the capacity of an existing mine are capitalized and amortized using the units-of-production method. In addition, the proceeds from the incidental sale of coal during development are recorded as a reduction of the related mine development costs.

Other Non-Current Assets

Other non-current assets include advance royalties and amounts held by third parties to guarantee performance on the delivery of coal, reclamation bonds, and other performance guarantees. The amounts pledged are restricted for the term of the bonds and cannot be withdrawn without the consent of the bonding companies.

Rights to leased coal and the related surface land can be acquired through royalty payments. Where royalty payments represent prepayments recoupable against future production, they are recorded as a prepaid asset, and amounts expected to be

recouped within one year are classified as a current asset. As mining occurs on these leases, the prepayment is charged to cost of coal sales. See Note 15, "Royalties," for further details of royalty agreements.

Also included within other non-current assets are deferred financing costs associated with the 2012 Credit Facility, which are subject to amortization over the term of the obligation using the effective interest method. In November 2016, the 2012 Credit Facility was terminated and the remaining unamortized deferred financing costs were written-off. See Note 12, "Long-Term Debt," for further details regarding the termination of the credit facility.

Investments

Investments and ownership interests are accounted for under the equity method of accounting if the Company has the ability to exercise significant influence, but not control, over the entity. If the Company does not have control and cannot exercise significant influence, the investment is accounted for using the cost method. See Note 13, "Related-Party Transactions," for further details regarding the Company's investment in Thoroughbred.

Long-Lived Assets

If facts and circumstances suggest that a long-lived asset may be impaired, the carrying value is reviewed for recoverability. If this review indicates the carrying value of the asset will not be recovered, as determined based on projected undiscounted cash flows related to the asset over its remaining life, the carrying value of the asset is reduced to its estimated fair value through an impairment loss.

During the year ended December 31, 2016 and 2015, the Company recorded an asset impairment charge of $4,431 and $137,678, respectively. No asset impairment charges were recorded during the year ended December 31, 2014. See Note 4, "Asset Impairment and Restructuring Charges," for further details regarding the impairment charges recognized.

Asset Retirement Obligations (ARO) and Reclamation

The Company’s ARO activities consist of estimated spending related to reclaiming surface land and support facilities at both surface and underground mines in accordance with federal and state reclamation laws as defined by each mining permit. Obligations are incurred when development of a mine commences for underground mines and surface facilities or, in the case of support facilities, refuse areas and slurry ponds when construction begins.

The obligation’s fair value is determined using discounted cash flow techniques and is accreted to its present value at the end of each period. The Company estimates ARO liabilities for final reclamation and mine closure based upon detailed engineering calculations of the amount and timing of future cash spending for a third party to perform the required work. Spending estimates are escalated for inflation and then discounted at the credit-adjusted, risk-free rate. The Company records an ARO asset associated with the discounted liability for final reclamation and mine closure. The obligation and corresponding asset are recognized in the period in which the liability is incurred. The ARO asset is amortized using the units-of-production method over the estimated recoverable reserves that are associated with the property being benefited. The ARO liability is accreted to the projected spending date. As changes in estimates occur (such as mine plan revisions, changes in estimated costs, or changes in timing of performance of reclamation activities), the revisions to the obligation and asset are recognized at the appropriate credit-adjusted, risk-fee rate.

Fair Value

For assets and liabilities that are recognized or disclosed at fair value in the consolidated financial statements, the Company defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

Derivatives

Derivative instruments are accounted for in accordance with the applicable FASB guidance on accounting for derivative instruments and hedging activity. This guidance provides comprehensive and consistent standards for the recognition and measurement of derivative and hedging activities. It also requires that derivatives be recorded on the consolidated balance sheet at fair value and establishes criteria for hedges of changes in fair values of assets, liabilities, or firm commitments; hedges of variable cash flows of forecasted transactions; and hedges of foreign currency exposures of net investments in foreign operations. The Company did not have any outstanding derivative instruments as of December 31, 2016 and 2015.

Income Taxes

The Company is subject to taxation. Deferred income taxes are recorded by applying statutory tax rates in effect at the date of the balance sheet to differences between the income tax bases of assets and liabilities and their carrying amounts for financial reporting purposes. Deferred tax assets are reduced by a valuation allowance if, based on the weight of available evidence, it is more likely than not that some portion or all of the deferred tax assets will not be realized. In determining whether a valuation allowance is appropriate, projected realization of tax benefits is considered based on expected levels of future taxable income, available tax planning strategies, and the overall deferred tax position. If actual results differ from the assumptions made in the evaluation of the amount of the valuation allowance, the Company records a change in the valuation allowance through income tax expense in the period such determination is made. Certain subsidiaries are disregarded for income tax purposes and are included in each respective parent entity's tax returns.

The calculations of the Company's tax liabilities involve dealing with uncertainties in the application of complex tax regulations. The Company recognizes liabilities for uncertain tax positions based on the two-step process prescribed in Accounting Standards Codification Topic 740, *Income Taxes* (ASC 740). The first step is to evaluate the tax position for recognition by determining whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. The second step requires the Company to estimate and measure the tax benefit as the largest amount that is more than 50% likely to be realized upon settlement. The Company re-evaluates these uncertain tax positions annually. This evaluation is based on factors including, but not limited to, changes in facts or circumstances, changes in tax law, effectively settled issues under audit, or new audit activity. Such a change in recognition or measurement results in the recognition of a tax benefit or an additional charge to the tax provision.

Long-Term Obligation to Related Party

The Company has entered into certain transactions with its affiliate, Thoroughbred, whereby it has sold an undivided interest in certain of its land and mineral reserves and subsequently entered into a lease agreement to mine the acquired mineral reserves in exchange for a production royalty. Due to its continuing involvement in the land and mineral reserves transferred, these transactions have been accounted for as financing arrangements and a long-term obligation has been established that is being amortized at an annual rate of 7% of the estimated gross revenue generated from the sale of the coal originating from the leased mineral reserves. The effective interest rate of the obligation is based on various estimates in future pricing and production quantities within the Company's mine plans and is adjusted prospectively as significant changes in its mine plans occur. See Note 13, "Related-Party Transactions," for further discussion of transactions with Thoroughbred.

Benefit Plans

Effective January 1, 2013, the Company began providing certain health care benefits, including the reimbursement of a portion of out-of-pocket costs associated with insurance coverage, to qualifying salaried and hourly retirees and their dependents. The cost of providing these benefits is determined on an actuarial basis and accrued over the employee's period of active service.

The Company recognizes the underfunded status of this plan, as determined on an actuarial basis, on the balance sheet and the changes in the funded status are recognized in other comprehensive income (loss). Actuarial gains and losses are amortized using the corridor approach over the average future service period of current active plan participants expected to receive benefits. See Note 19, "Employee Benefit Plans," for additional disclosures relating to these obligations.

Workers' Compensation and Black Lung Benefits

Under the Black Lung Benefits Revenue Act of 1977 and the Black Lung Benefits Reform Act of 1977, as amended in 1981, each coal mine operator must pay federal black lung benefits to claimants who are current and former employees and also make payments to a trust fund for the payment of benefits and medical expenses to eligible claimants who last worked in the coal industry prior to January 1, 1970. The trust fund is funded by an excise tax on production. For the years ended December 31, 2016, 2015, and 2014, the Company recorded $5,048, $6,313, and $7,341, respectively, of expense related to this excise tax. The Company has no liability associated with current claims under state statutes or the Federal Coal Mine Health and Safety Act of 1969, as amended, to pay black lung benefits to eligible employees, former employees and their dependents, as any obligations are either secured by insurance or paid from the federal trust fund established for that purpose. The Company has recognized a liability for potential future claims by current employees based on the service cost method estimated by an

independent actuary. The liability incorporates assumptions regarding medical costs, allocated loss adjustment expense, claim development patterns, and interest rates. For the year ended December 31, 2016, the Company recorded expense associated with future black lung claims of $419 and had a related liability of $1,828, which is included as a component of other long-term liabilities in the consolidated balance sheet.

With regard to workers' compensation, the Company provides benefits to its employees by being insured through an insurance carrier. Premium expense for workers' compensation benefits is recognized in the period in which the related insurance coverage is provided.

Investment Credits

For establishing operations in Ohio County, Kentucky, the Company qualified for investment credits totaling $16,000 recoverable from the State of Kentucky to be applied against certain state income and employee payroll taxes paid. Investment credits, which expire in 2021, are accounted for using the deferral method. During the years ended December 31, 2016, 2015, and 2014, the Company recognized $1,141, $1,953, and $2,359, respectively, in investment credits, which were applied against certain employee payroll taxes in the statement of operations. As of December 31, 2016 and 2015, the Company had $4,237 and $5,378, respectively, in investment credit carryforwards available.

Equity Awards

The Company accounts for share-based compensation at the grant date fair value of awards and recognizes the related expense over the vesting period of the award.

3. LIQUIDITY AND GOING CONCERN

The principal indicators of the Company's liquidity are cash on hand and, prior to its termination, availability under the 2012 Credit Facility. As more fully described below in Note 12, "Long-Term Debt," the Company terminated the 2012 Credit Facility effective November 14, 2016. The Company's available liquidity as of December 31, 2016 was $57,505, which was comprised solely of cash on hand.

The Company has experienced recurring losses from operations, which has led to a substantial decline in cash flows from operating activities for the year ended December 31, 2016. The Company's current operating plan indicates that it will continue to incur losses from operations and generate negative cash flows from operating activities. In addition, the Company entered into a settlement agreement, effective March 29, 2017, with Thoroughbred whereby the Company agreed, among other things, to begin paying Thoroughbred all production royalties earned on or after January 1, 2017 in cash. See Note 13, "Related-Party Transactions," for more information with respect to the settlement agreement. The Company's continuing operating losses, negative cash flow projections and other liquidity risks raise substantial doubt about whether the Company will meet its obligations as they become due within one year after the date of this report. As a result of this, as well as the continued uncertainty around future coal fundamentals, the Company has concluded there exists substantial doubt regarding its ability to continue as a going concern.

The accompanying consolidated financial statements have been prepared assuming the Company will continue as a going concern, which contemplates the realization of assets and liabilities and commitments in the normal course of business. The consolidated financial statements for the year ended December 31, 2016 do not include any adjustments that may result from uncertainty related to the Company's ability to continue as a going concern. The report from the Company's independent registered public accounting firm on its consolidated financial statements for the year ended December 31, 2016 includes an explanatory paragraph regarding its ability to continue as a going concern.

Due to the Company's current financial outlook, it has undertaken steps to preserve its liquidity and manage operating costs, including controlling capital expenditures. Beginning in 2015, the Company undertook steps to enhance its financial flexibility and reduce cash outflows in the near term, including a streamlining of its cost structure and anticipated reductions in production volumes and capital expenditures. In addition, the Company is actively negotiating a restructuring with advisers to certain holders of the Notes (the Holders), who collectively beneficially own or manage in excess of 75% of the aggregate principal amount of the Notes.

The Company has engaged financial and legal advisers to assist in restructuring its capital structure and evaluating other potential alternatives to address the impending liquidity constraints. However, there can be no assurance that any restructuring will be possible on acceptable terms, if at all. It may be difficult to come to an agreement that is acceptable to all of the

Company's creditors. The Company's failure to reach an agreement on the terms of a restructuring with its creditors would have a material adverse effect on the Company's liquidity, financial condition and results of operations. In addition, if a successful restructuring with the Holders of the Notes is not achieved, it may be necessary for the Company to file a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code in order to implement a restructuring, or the Company's creditors could force it into an involuntary bankruptcy or liquidation.

4. ASSET IMPAIRMENT AND RESTRUCTURING CHARGES

For the years ended December 31, 2016, 2015, and 2014, the Company recognized asset impairment and restructuring charges of $4,431, $138,679, and zero, respectively. The following summarizes the details of these charges, which are included within "Asset impairment and restructuring charges" in the consolidated statement of operations.

2016 Charges

In October 2010, the Company entered into a lease agreement for over 100 million tons of recoverable coal reserves located in Union and Webster Counties, Kentucky in exchange for a production royalty. The initial term of the lease expired on June 1, 2016. In addition, the lease required the Company to provide the lessor with a certain amount of coal tonnage annually until production commenced on the leased reserve. The Company valued this coal tonnage using the prevailing average market price, and the advance royalty was recoupable against production royalties generated by future mining activity.

Upon expiration, the lease was renewed for an additional five year term. The terms of the renewal stipulate a minimum annual rent payable with a specified amount of coal tonnage beginning on June 1, 2017. In addition, the lease allows for the early termination of the agreement by the Company upon payment of a termination fee, as defined, which is zero through December 1, 2017. Lastly, the minimum annual rent, including amounts previously paid, will no longer be recoupable against future production royalties. As a result, the Company recognized a non-cash impairment charge of $3,381 during the second quarter of 2016 to write-off advanced royalties associated with the aforementioned lease.

An additional impairment charge of $1,050 was recognized during the fourth quarter of 2016. The charge related to the write-off of advance royalties associated with certain leased property in Union County, Kentucky, as the as amounts are no longer recoupable due to the termination of the lease in December 2016.

2015 Charges

Due to the significant decline in thermal coal pricing experienced during the year ended December 31, 2015 and the continuation of other adverse market conditions, the Company concluded indicators of impairment existed as of September 30, 2015. As such, the Company performed a comprehensive review of its long-lived assets for recoverability through future cash flows as of September 30, 2015. Based on that review, it was determined the carrying value was not recoverable, and the Company correspondingly recognized a non-cash asset impairment charge of $137,678 to reduce the carrying value of its long-lived assets to their estimated fair value. The inputs used to measure the fair value of the Company's long-lived assets were largely unobservable, and accordingly, this measure was classified as Level 3. The fair value, which was determined through the use of a third-party specialist, was estimated primarily based on the income approach, with the significant inputs including future cash flow projections and discount rate assumptions. The impairment charge has been allocated to each of the components that comprise property, plant, equipment, and mine development, which is reflected in the amounts included in Note 6, "Property, Plant, Equipment, and Mine Development," for the year ended December 31, 2015 .

In addition, the Company initiated certain restructuring activities beginning during the three months ended September 30, 2015 to better align its cost structure with current industry conditions. In order to optimize its coal production and focus on its low-cost operations, effective December 31, 2015, the Company idled its Midway surface mine, reduced operations to one section at the Parkway underground mine, and reduced the workforce at two of its preparation plants.

Costs associated with these restructuring activities primarily include voluntary and involuntary workforce rationalization. For the year ended December 31, 2015, the Company recognized a restructuring charge of $1,001. The majority of cash expenditures associated with the 2015 charge were paid in the first half of 2016.

5. INVENTORIES

Inventories consist of the following amounts as of December 31, 2016 and 2015:

	2016	2015
Materials and supplies	**$ 8,610**	$ 9,634
Coal—raw and saleable	**3,199**	4,928
Total	**$ 11,809**	$ 14,562

6. PROPERTY, PLANT, EQUIPMENT, AND MINE DEVELOPMENT

Property, plant, equipment, and mine development consist of the following as of December 31, 2016 and 2015:

	2016	2015
Land	**$ 41,928**	$ 41,909
Mineral rights	**96,755**	96,755
Machinery and equipment	**190,822**	183,810
Buildings and facilities	**63,588**	63,436
Office equipment, software and other	**17,386**	17,386
Mine development costs	**54,050**	54,025
ARO assets	**5,462**	6,798
Construction-in-progress	**9,177**	11,656
	479,168	475,775
Less: accumulated depreciation, depletion, and amortization	**245,402**	214,377
Total	**$ 233,766**	$ 261,398

Depreciation expense, including amounts from capitalized leases, for the years ended December 31, 2016, 2015, and 2014, was $27,386, $32,367, and $29,394, respectively. For the years ended December 31, 2016, 2015, and 2014, depletion expense related to mineral rights amounted to $1,888, $4,835, and $7,139, respectively; and amortization expense related to mine development costs amounted to $1,765, $10,032, and $9,940, respectively.

The Company has pledged substantially all buildings and equipment as security under the Notes (see Note 12), as well as under certain capital lease obligations.

The Company had outstanding construction commitments as of December 31, 2016, of approximately $72. All construction commitments are expected to be completed within the next fiscal year.

7. CLOSURE OF LEWIS CREEK UNDERGROUND MINE

The Company's Lewis Creek underground mine, which produced coal from the West Kentucky #9 seam, experienced significant operating inefficiencies due to the geological conditions of the portion of the reserve being mined. As a result of the ongoing mining difficulties, a final decision was made in August 2014 not to continue advancing under the existing mine plan, but rather to retreat and mine only in the eastern portion of the reserve.

The Company completed mining of the Lewis Creek underground mine in March 2015 and has extracted the equipment, which will be utilized at its other mining operations in the future. As a result of the closure, the Company accelerated depreciation of the remaining net book value of the capitalized costs associated with the original development of the mine. Total expense recognized during 2015 to write-off the remaining asset was approximately $6,318, which is included as a component of "depreciation, depletion, and amortization" in the consolidated statement of operations for the year ended December 31, 2015.

8. OTHER NON-CURRENT ASSETS

Other non-current assets consist of the following as of December 31, 2016 and 2015:

	2016	2015
Escrows and deposits	**$ 5,216**	$ 5,233
Restricted surety and cash bonds	**6,002**	6,115
Advanced royalties	**1,413**	5,272
Deferred financing costs, net associated with the 2012 Credit Facility	**—**	697
Intangible assets, net	**52**	70
Total	**$ 12,683**	$ 17,387

In November 2016, the 2012 Credit Facility was terminated and the remaining unamortized deferred financing costs were written-off. See Note 12, "Long-Term Debt," for further details regarding the termination of the credit facility.

9. ACCRUED AND OTHER LIABILITIES

Accrued and other liabilities consist of the following amounts as of December 31, 2016 and 2015:

	2016	2015
Payroll and related benefits	**$ 4,804**	$ 6,454
Taxes other than income taxes	**3,566**	3,134
Interest	**979**	987
Asset retirement obligations	**133**	94
Royalties	**610**	630
Other	**1,745**	1,746
Total	**$ 11,837**	$ 13,045

10. FAIR VALUE OF FINANCIAL INSTRUMENTS

The Company measures the fair value of assets and liabilities using a three-tier fair value hierarchy which prioritizes the inputs used in measuring fair value as follows: Level 1—observable inputs such as quoted prices in active markets; Level 2—inputs, other than quoted market prices in active markets, which are observable, either directly or indirectly; and Level 3—valuations derived from valuation techniques in which one or more significant inputs are unobservable. In addition, the Company may use various valuation techniques including the market approach, using comparable market prices; the income approach, using the present value of future income or cash flow; and the cost approach, using the replacement cost of assets.

The Company's financial instruments consist of cash equivalents, accounts receivable, long-term debt, and other long-term obligations. For cash equivalents, accounts receivable and other long-term obligations, the carrying amounts approximate fair value due to the short maturity and financial nature of the balances. The estimated fair market values of the Company's Notes, which was determined using Level 2 inputs, and long-term obligation to related party, which was determined using Level 3 inputs, are as follows:

	December 31, 2016		December 31, 2015	
	Fair Value	Carrying Value	Fair Value	Carrying Value
Notes(1)	**$ 126,000**	**$ 191,191**	$ 82,000	$ 188,890
Long-term obligation to related party	**113,106**	**147,536**	94,811	128,809
Total	**$ 239,106**	**$ 338,727**	$ 176,811	$ 317,699

(1) The carrying value of the Notes is net of the unamortized original issue discount (OID) and deferred financing costs as of December 31, 2016 and 2015.

The fair value of the Notes is based on quoted market prices, while the fair value of the long-term obligation to related party was based on estimated cash flows discounted to their present value.

11. RISKS AND CONCENTRATIONS

Geographical Concentration

The Company's operations are concentrated in western Kentucky, and a disruption within that geographic region could adversely affect the Company's performance.

Customer Concentration

The Company has multi-year coal supply agreements with multiple customers. The top two customers accounted for approximately 45% and 40%, respectively, of net sales for the year ended December 31, 2016. The Company seeks to mitigate credit risk by monitoring creditworthiness of these customers and adjusting credit amounts provided accordingly. Significant interruption to these customer facilities covered under force majeure provisions of their contracts could adversely affect the Company's results.

12. LONG-TERM DEBT

The Company's total indebtedness as of December 31, 2016 and 2015 consisted of the following:

Type	2016	2015
Notes	**$ 191,191**	$ 188,890
Other	**16,066**	23,020
	207,257	211,910
Less: current maturities	**8,217**	8,402
Total long-term debt	**$ 199,040**	$ 203,508

Senior Secured Notes due 2019

On December 21, 2012, the Company completed a $200,000 offering of 11.75% Notes. The Notes were issued at an OID of 96.567%. The OID was recorded on the Company's balance sheet as a component of long-term debt, and is being amortized to interest expense over the life of the notes. As of December 31, 2016 and 2015, the unamortized OID was $3,622 and $4,581, respectively. The Company incurred $8,358 of deferred financing fees related to the Notes, which have been capitalized and are being amortized over the life of the Notes. As of December 31, 2016 and 2015, the unamortized deferred financing costs were $5,187 and $6,529, respectively.

Interest on the Notes is due semiannually on June 15 and December 15 of each year, with the first payment made on June 15, 2013. The Company may redeem the Notes, in whole or in part, at any time during the 12 months commencing on December 15, 2016 at 105.875% of the principal amount redeemed, at any time during the 12 months commencing December 15, 2017 at 102.938% of the principal amount redeemed, and at any time after December 15, 2018 at 100.000% of the principal amount redeemed, in each case plus accrued and unpaid interest to the applicable redemption date.

Upon the occurrence of an event of a Change of Control (as defined in the indenture governing the Notes), unless the Company has exercised its right to redeem the Notes, the Company will be required to make an offer to purchase the Notes at a redemption price of 101.000%, plus accrued and unpaid interest to the date of repurchase.

Subject to certain customary release provisions, the Notes are fully and unconditionally guaranteed, jointly and severally, on a senior secured basis, by the Company and substantially all of its current and future domestic restricted subsidiaries (as defined). They are also secured, subject to certain exceptions and permitted liens, on a first-priority basis by substantially all of the assets of the Company and the guarantors that do not secure the 2012 Credit Facility (see below), or any successor or replacement credit facility, on a first-priority basis. Subject to certain exceptions and permitted liens, the Notes are also secured on a second-priority basis by a lien on the assets securing the Company's obligations under the 2012 Credit Facility, or any successor or replacement credit facility, on a first-priority basis.

The indenture governing the Notes contains restrictive covenants which, among other things, limit the ability (subject to exceptions) of the Company and its restricted subsidiaries (as defined) to: (i) incur additional indebtedness or issue preferred equity; (ii) pay dividends or distributions on or purchase the Company's stock or the Company's restricted subsidiaries' stock;

(iii) make certain investments; (iv) use assets as security in other transactions; (v) create guarantees of indebtedness by restricted subsidiaries; (vi) enter into agreements that restrict dividends, distributions, or other payment by restricted subsidiaries; (vii) sell certain assets or merge with or into other companies; and (viii) enter into transactions with affiliates.

The Company and the guarantor subsidiaries entered into a registration rights agreement (the Registration Rights Agreement) in connection with the issuance and sale of the Notes. Pursuant to the Registration Rights Agreement, the Company and the guarantor subsidiaries agreed to file a registration statement with the Securities and Exchange Commission (SEC) to register an exchange offer pursuant to which the Company will offer to exchange a like aggregate principal amount of senior notes identical in all material respects to the Notes, except for terms relating to transfer restrictions, for any or all of the outstanding Notes. The exchange offer was completed in November 2013.

On February 2, 2017, the Company received notice from legal counsel representing certain of the Holders of the Notes regarding an alleged Event of Default. See Note 21, "Commitments and Contingencies," for further information regarding this claim.

2012 Credit Facility

Concurrently with the closing of the Notes offering on December 21, 2012, the Company entered into a new asset-based revolving credit facility, the 2012 Credit Facility. The 2012 Credit Facility, which was subsequently terminated in November 2016, provided for a five-year, $50,000 revolving credit facility that would expire on December 21, 2017 . Borrowings under the 2012 Credit Facility may not exceed a borrowing base, as defined within the agreement. In addition, the 2012 Credit Facility included a $10,000 letter of credit sub-facility and a $5,000 swingline loan sub-facility. As of December 31, 2015, the Company had $16,740 available for borrowing under the facility. The Company incurred $1,198 of deferred financing fees related to the 2012 Credit Facility that were capitalized and amortized to interest expense over the life of the facility.

Interest and Fees

Borrowings under the 2012 Credit Facility bore interest, at the Company's option, at a rate based on (i) LIBOR, plus a margin ranging from 3.5% to 4.0%, or (ii) a base rate, plus a margin ranging from 2.5% to 3.0%. Margins could be increased by 2.0% per annum during the existence of any event of default. The Company was also required to pay certain other fees with respect to the 2012 Credit Facility, including: (i) an unused commitment fee ranging from 0.50% to 0.375% in respect of unutilized commitments, (ii) a fronting fee equal to 0.25% per annum of the amount of outstanding letters of credit and (iii) customary annual administration fees.

Collateral and Guarantors

The 2012 Credit Facility was secured by substantially all of the Company's and its subsidiaries' assets (other than certain excluded assets), with (i) a first priority lien on the ABL Priority Collateral (as defined) and (ii) a second priority lien on the Notes Priority Collateral (as defined). The 2012 Credit Facility was also guaranteed on a full and unconditional basis by the same subsidiaries of the Company that guarantee the Notes.

Restrictive Covenants and Other Matters

The 2012 Credit Facility included customary covenants that, subject to certain exceptions, restricted the Company's ability and the ability of the Company's subsidiaries to, among other things, incur indebtedness (including capital leases), create liens on assets, make investments, loans, guarantees, advances or acquisitions, pay dividends and distributions, liquidate, merge or consolidate, divest assets, engage in certain transactions with affiliates, create joint ventures or subsidiaries, change the nature of the Company's business, change the Company's fiscal year, issue stock, amend organizational documents, make capital expenditures and provide negative pledges on assets. In addition, at any time when (i) undrawn availability is less than the greater of (a) $10,000 or (b) an amount equal to 20% of the borrowing base or (ii) an event of default had occurred and was continuing, the Company would have been required to maintain a fixed charge coverage ratio, calculated as of the end of each calendar month for the twelve months then ended, greater than 1.0 to 1.0. The fixed charge coverage ratio was defined as the ratio of consolidated EBITDA to fixed charges, which includes the sum of unfinanced capital expenditures, scheduled principal payments on indebtedness, cash interest payments, dividends, and cash taxes.

The 2012 Credit Facility also contained customary affirmative covenants and events of default. If an event of default occurs, the lenders under the 2012 Credit Facility would be entitled to take various actions, including the acceleration of amounts due under the facility and all actions permitted to be taken by a secured creditor.

During 2016, the Company's fixed charge coverage ratio was less than 1.0-to-1.0, which would have required the Company to maintain minimum availability greater than $10,000 if any amounts were drawn on the 2012 Credit Facility. Since its inception, the Company had not borrowed under the 2012 Credit Facility, and, therefore, was not subject to the requirements of the financial covenants included within the agreement. Due to the restrictions imposed as a result of not maintaining the minimum fixed charge coverage ratio, the Company made the decision to terminate the 2012 Credit Facility effective November 14, 2016. Pursuant to this termination, the Company recognized a loss of $403, which is included as a component of "other, net" in the consolidated statement of operations, to write-off the remaining unamortized deferred financing costs associated with the 2012 Credit Facility.

Other Debt

Other debt consists of miscellaneous debt obligations entered into to finance the acquisition of certain equipment and land. These obligations have various maturities of one to five years and bear interest at rates between 2.99% and 6.50%.

Maturities of Long-Term Debt

The aggregate amounts of long-term debt maturities subsequent to December 31, 2016 were as follows:

2017	$	8,217
2018		5,133
2019		202,692
2020		—
2021		—
2022 and thereafter		24
Total	$	216,066

13. RELATED-PARTY TRANSACTIONS

Investments

Effective September 1, 2016, Yorktown exercised its right under the Second Amended and Restated Agreement of Limited Partnership of Thoroughbred Resources, LP to remove ECGP as the general partner of Thoroughbred. The Company received cash of $500 for its 0.2% general partner interest and recognized a pre-tax loss of $320, which is included as a component of "other, net" in the consolidated statement of operations for the year ended December 31, 2016.

Prior to September 1, 2016, the Company’s investment in Thoroughbred was accounted for under the equity method. Income from the equity interest in Thoroughbred for the years ended December 31, 2016, 2015, and 2014 totaled $89, $153, and $150, respectively. The Company continues to maintain a 0.9% interest in Thoroughbred through its subsidiary, Armstrong Energy Holdings, Inc., but, as a result of its removal as general partner, no longer has the ability to exercise significant influence over Thoroughbred. As such, effective September 1, 2016, the remaining investment in Thoroughbred retained by the Company is being accounted for under the cost method.

Sale of Coal Reserves

The Company has executed the sale of an undivided interest in certain land and mineral reserves located in Ohio and Muhlenberg Counties, Kentucky (the Jointly-Owned Property) to Thoroughbred, through a series of transactions beginning in February 2011. Subsequently, the Company entered into lease agreements with Thoroughbred pursuant to which Thoroughbred granted the Company leases to its undivided interests in the mining properties acquired and licenses to mine and sell coal from those properties in exchange for a production royalty. Due to the Company’s continuing involvement in the Jointly-Owned Property, these transactions have been accounted for as financing arrangements. A long-term obligation has been established that is being amortized over the anticipated life of the mineral reserves, at an annual rate of 7% of the estimated gross revenue generated from the sale of the coal originating from the leased mineral reserves. In addition, effective February 2011, the Company and Thoroughbred entered into a Royalty Deferment and Option Agreement, as amended (the Royalty Agreement), whereby the Company has been granted an option to defer payment of any royalties earned by Thoroughbred on coal mined from these properties. Compensation for the aforementioned transactions has consisted of a combination of cash payments and the forgiveness of amounts owed by the Company, which primarily consisted of deferred royalties.

On May 1, 2015, the Company sold a 12.10% undivided interest in the Jointly-Owned Property to Thoroughbred in exchange for Thoroughbred forgiving amounts owed by the Company of $18,172. On June 1, 2016, the Company sold an additional 17.81% undivided interest in the Jointly-Owned Property to Thoroughbred in exchange for Thoroughbred forgiving amounts owed by the Company of $16,413. The amounts forgiven consisted primarily of deferred production royalties. The newly acquired interests in the mineral reserves were leased and/or subleased by Thoroughbred to the Company in exchange for a production royalty. These transactions were accounted for as financing arrangements, and additional long-term obligations to Thoroughbred of $18,172 and $16,413 were recognized on May 1, 2015 and June 1, 2016, respectively.

The percentage interest in the Jointly-Owned Property sold to Thoroughbred in the above transactions was based on fair values determined by a third-party specialist as of December 31 of the year prior to the completion of the applicable land and mineral reserve sale. In addition, these transactions were approved by the conflicts committee of the board of directors of the Company, a committee including independent directors. As a result of the above, Thoroughbred's undivided interest in the Jointly-Owned Property as of December 31, 2016 and 2015 was 79.19% and 61.38%, respectively.

As of December 31, 2016 and 2015, the outstanding long-term obligation to related party totaled $147,536 and $128,809, respectively. Interest expense recognized for the years ended December 31, 2016, 2015, and 2014 associated with the long-term obligation to related party was $7,604, $10,049, and $7,993, respectively. The effective interest rate of the long-term obligation to related party, which is adjusted based on significant mine plan changes and the completion of the periodic reserve transfers, was 6.42% as of December 31, 2016.

Based on the current mine plan and estimated selling prices of the coal, estimated payments under the obligation are as follows:

Year ending December 31:		
2017	$	7,881
2018		9,711
2019		11,402
2020		13,242
2021		6,113
2022 and thereafter		719,397
Total payments	$	767,746

Lease of Coal Reserves

In February 2011, Thoroughbred entered into a lease and sublease agreement with the Company relating to its Elk Creek reserves and granted the Company a license to mine coal on those properties. The terms of this agreement mirror those of the lease agreements associated with the jointly owned reserves between the Company and Thoroughbred. Total production royalties owed from mining of the Elk Creek reserves, where the Company's Kronos underground mine resides, for the years ended December 31, 2016, 2015, and 2014 totaled $7,121, $7,879, and $8,269, respectively.

Administrative Services Agreements

Effective as of January 1, 2011, the Company entered into an Administrative Services Agreement with Thoroughbred and its then current general partner, ECGP, pursuant to which the Company agreed to provide Thoroughbred with general administrative and management services, including, but not limited to, human resources, information technology, financial and accounting services and legal services. The administrative service fee, which is adjusted annually, is approved by the conflicts committee of the board of directors. As consideration for the use of the Company's employees and services, and for certain shared fixed costs, Thoroughbred paid the Company $942, $1,200, and $1,015 for the years ended December 31, 2016, 2015, and 2014, respectively.

In connection with ECGP's removal as general partner of Thoroughbred, the Company and Thoroughbred agreed to terminate the Administrative Services Agreement effective December 31, 2016.

Settlement Agreement

On December 16, 2016, the Company received notification from legal counsel for Thoroughbred Holdings GP, LLC (Thoroughbred Holdings), the general partner of Thoroughbred, disputing the calculation of deferred royalties and valuation of

the Jointly-Owned Property pursuant to the terms of the Royalty Agreement. In the December 16th correspondence, counsel for Thoroughbred Holdings asserted that certain third-party valuations prepared in order to ascertain the amount of the Jointly-Owned Property to be transferred from us to Thoroughbred pursuant to the Royalty Agreement to satisfy production royalties due to Thoroughbred were inaccurate for fiscal year 2016 and prior years. Therefore, according to Thoroughbred, its ownership in the Jointly-Owned Property would have reached 100% during or prior to fiscal year 2016.

The Company promptly notified Thoroughbred that it disputed these assertions and requested information supporting Thoroughbred's arguments. Following the Company's request, in a letter dated January 6, 2017, Thoroughbred Holding's CEO advised the Company that Thoroughbred, based on its analysis, concluded that Armstrong's valuation of the remaining Jointly-Owned Property was significantly overstated, and using its valuation methodology, Thoroughbred would have been entitled to 100% ownership of the Jointly-Owned Property during the first half of 2016. Therefore, according to Thoroughbred's calculations, cash payment of production royalties was required for a portion of the royalties incurred during 2016 and thereafter. In addition, Thoroughbred questioned several of the inputs utilized in the valuation by the Company during prior years, therefore challenging the validity of the prior land and reserve transfers.

By subsequent letter dated February 15, 2017, Thoroughbred clarified that its valuation analysis ascertained that the fair market value of the entirety of the Jointly-Owned Property as of December 31, 2016 was not more than $35,000. In addition, Thoroughbred insisted that applying more conservative inputs to the valuations of prior periods resulted in the underpayment of production royalties by not less than $26,000 and potentially in excess of $40,000 through December 31, 2016. Thoroughbred's counsel, by separate letter dated February 15, 2017, also took exception to the Company's calculation of the amount of deferred royalties for the year ended December 31, 2016, the amount of certain offsets from these deferred royalties by amounts due from Thoroughbred to Armstrong pursuant to an Administrative Services Agreement, and the offset of certain production royalties that the Company overpaid to Thoroughbred on properties other than the Jointly-Owned Property. The Company subsequently notified Thoroughbred of its continued disagreement with their claims.

Following a series of negotiations, Armstrong and certain of its affiliates, and Thoroughbred Holdings and certain of its affiliates, entered into a settlement agreement effective March 29, 2017 (the Settlement Agreement) to resolve all of these claims and to avoid the uncertainties of a potential lengthy arbitration. Under the terms of the Settlement Agreement, in exchange for the Company's transfer of a 20.81% undivided interest in the transferable Jointly-Owned Property, the Company and Thoroughbred Holdings agreed to mutual waivers and releases related to the Royalty Agreement, the payment of production royalties or any other sums due under the leases prior to January 1, 2017, and the Administrative Services Agreement. Thoroughbred also waived and released any prior claims against the Company for lost or wasted coal or mining practices and operational decisions made by the Company; any other demands, claims, or assertions set forth in the various communications from Thoroughbred Holdings and its legal counsel to the Company; and any other claims arising from Armstrong's administration of the leases prior to January 1, 2017. In addition, the Company agreed to begin paying Thoroughbred all production royalties earned on or after January 1, 2017 in cash pursuant to the existing lease terms, with royalties earned for January and February 2017 totaling $2,651 being paid on March 31, 2017.

As a result of the Settlement Agreement, the Company recognized a non-cash charge in the year ending December 31, 2016 totaling $10,542 related to the 9.86% increase in the Jointly-Owned Property transferred to resolve the aforementioned disputes. The 9.86% interest in the Jointly-Owned Property represents production royalties that were expected to be earned by Thoroughbred in the first half of 2017, which would have resulted in Thoroughbred's interest in the Jointly-Owned Property reaching 100.0%. Effective with the execution of the Settlement Agreement, amounts accrued to Thoroughbred totaling $11,701 as of December 31, 2016 were forgiven as consideration for the transfer of the remaining interest in the Jointly-Owned Property. In addition, the Jointly-Owned Property that was the subject of the dispute has been leased and/or subleased by Thoroughbred to the Company in exchange for a production royalty effective January 1, 2017. As a result of the Company's continuing involvement in the land and mineral reserves transferred to Thoroughbred, this transaction is accounted for as a financing arrangement, and, therefore, will result in an increase to the long-term obligation to Thoroughbred totaling $22,243 during the first quarter of 2017.

Other

In 2006 and 2007, the Company entered into an overriding royalty agreement with an executive employee to compensate him $0.05/ton of coal mined and sold from properties owned by certain subsidiaries of the Company. The agreement remains in effect for the later of 20 years from the date of the agreement or until all salable coal has been extracted. The royalty agreement transfers with the property regardless of ownership or lease status. The royalties are payable the month following the sale of coal mined from the specified properties. The Company accounts for the royalty arrangement as expense in the period in which the coal is sold. Expense recorded in the years ended December 31, 2016, 2015, and 2014, was $209, $316, and $408, respectively.

14. LEASE OBLIGATIONS

The Company leases equipment and facilities directly under various non-cancelable lease agreements. Certain leases contain renewal or purchase terms in the contract. Rental expense under operating leases was $5,595, $15,024, and $17,873 for the years ended December 31, 2016, 2015, and 2014, respectively.

Future minimum lease payments under non-cancelable operating leases (with initial or remaining lease terms in excess of one year) and future minimum capital lease payments as of December 31, 2016, are:

	Capital Leases	Operating Leases
Year ending December 31:		
2017	$ 568	$ 4,239
2018	—	636
2019	—	95
2020	—	—
2021 and thereafter	—	—
Total minimum lease payments	568	$ 4,970
Less: amount representing interest	13	
Present value of net minimum capital lease payments	555	
Less: current installments of obligations under capital leases	555	
Obligations under capital leases, excluding current installments	$ —	

The net amount of leased assets capitalized on the balance sheet as of December 31, 2016 and 2015 is as follows:

	2016	2015
Asset cost	$ 15,421	$ 18,753
Less: accumulated depreciation	13,334	13,703
Net	$ 2,087	$ 5,050

15. ROYALTIES

Royalty expense, inclusive of royalties owed to a related party, for the years ended December 31, 2016, 2015, and 2014 were $11,768, $13,841, and $12,975, respectively. For the years ended December 31, 2016 and 2015, the Company recorded $722 and $1,040, respectively, of advance royalty payments. These payments are recoupable against royalties generated from future mining activity. As of December 31, 2016 and 2015, advance royalties totaled $1,413 and $5,272, respectively.

During 2016, the Company recognized a non-cash impairment charge of $4,431 to write-off certain advance royalties that are no longer deemed recoupable. See Note 4, "Asset Impairment and Restructuring Charges," for further discussion of the current year charge.

Anticipated future minimum advance royalties as of December 31, 2016, are payable as follows:

2017	$ 787
2018	766
2019	764
2020	746
2021 and thereafter	1,310
Total	$ 4,373

In addition to the above advanced royalties, production royalties are payable based on the quantity of coal mined in future years.

Various royalties and commissions have been negotiated with certain current and former executives of management, a former minority shareholder, and sales brokers. See Note 13, "Related-Party Transactions," for the terms of royalties to related-parties.

16. ASSET RETIREMENT OBLIGATIONS AND RECLAMATION

Asset retirement obligation and reclamation balances consist of the following as of December 31, 2016 and 2015:

	2016	2015
Balance at beginning of year	**$ 14,084**	$ 17,721
Accretion expense	**1,382**	1,774
Liabilities settled (net)	**(162)**	(2,341)
Revisions to estimates	**(1,115)**	(3,070)
Balance at end of year	**14,189**	14,084
Less: current obligation	**133**	94
Total obligation, less current portion	**$ 14,056**	$ 13,990

The credit-adjusted, risk-free rates used to discount the estimated liability were 12.8% and 11.9% in 2016 and 2015, respectively.

For the years ended December 31, 2016 and 2015, the reduction in the liability resulted primarily from overall changes in discount rates, estimates of the costs and scope of remaining reclamation work and fluctuations in projected mine life estimates.

17. INCOME TAXES

The loss before income taxes and non-controlling interest was ($58,713), ($162,798) and ($28,832) for the years ended December 31, 2016, 2015, and 2014, respectively. The income tax benefit recognized in the year ended December 31, 2015 is primarily related to the intraperiod allocation rules under ASC 740, which requires the income in other sources, such as other comprehensive income, be considered in determining the realization of the loss in continuing operations. Accordingly, a benefit was recorded in continuing operations with an offsetting expense recognized through other comprehensive income.

The components of the income tax (benefit) provision are as follows:

	December 31,		
	2016	2015	2014
Current:			
Federal	**$ —**	$ —	$ —
State	**117**	526	—
	117	526	—
Deferred:			
Federal	**—**	(1,000)	—
State	**—**	(183)	—
	—	(1,183)	—
Total	**$ 117**	$ (657)	**$ —**

The income tax rate differed from the U.S. federal statutory rate as follows:

	December 31,		
	2016	2015	2014
Tax benefit at federal statutory rates	**$ (20,549)**	$ (56,979)	$ (9,697)
State income taxes	**(3,449)**	(8,115)	(1,797)
Other permanent items	**721**	(185)	663
Other	**339**	(1,183)	(325)
Increase in valuation allowance	**23,055**	65,805	11,156
Total	**$ 117**	$ (657)	$ —

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and liabilities consist of the following:

	December 31,	
	2016	2015
Deferred tax assets:		
Tax loss and credit carryforwards	**$ 97,505**	$ 79,636
Long-term obligation to related party	**62,240**	51,763
Advanced royalty impairment	**1,162**	—
Deferred organization costs and other intangibles	**571**	666
Vacation accrual	**525**	676
Charitable contributions	**174**	139
Other post-retirement benefits	**2,764**	2,378
Asset retirement obligation	**7,190**	6,912
Other	**739**	373
Total gross deferred tax assets	**172,870**	142,543
Deferred tax liabilities:		
Property, plant, and equipment	**(46,389)**	(39,075)
Investments	**(169)**	(208)
Other	**(50)**	(53)
Total gross deferred tax liabilities	**(46,608)**	(39,336)
Valuation allowance	**(126,262)**	(103,207)
Net deferred tax assets	**$ —**	**$ —**

Changes to the valuation allowance during the years ended December 31, 2016 and 2015, were as follows:

Valuation allowance at December 31, 2014	$	37,402
Increase in valuation allowance		65,805
Valuation allowance at December 31, 2015		103,207
Increase in valuation allowance		**23,055**
Valuation allowance at December 31, 2016	**$**	**126,262**

The Company evaluated and assessed the expected near-term utilization of net operating loss carryforwards, book and taxable income trends, available tax strategies, and the overall deferred tax position and believes that it is more likely than not that the benefit related to the deferred tax assets will not be realized and has thus established the valuation allowance required as of December 31, 2016 and 2015. Based on the anticipated reversals of the Company's deferred tax assets and deferred tax liabilities, a valuation allowance of $126,262 and $103,207 at December 31, 2016 and 2015, respectively, has been established only for the excess of deferred tax assets over deferred tax liabilities.

The Company's net deferred tax assets included federal and state net operating loss (NOL) carryforwards of $234,018 and $383,943, respectively, as of December 31, 2016, and $192,330 and $305,379, respectively, as of December 31, 2015. The NOLs begin to expire in 2026. The Company's net deferred taxes also include $407 of alternative minimum tax (AMT) credits as of December 31, 2016 and 2015. These AMT credits have no expiration date.

The Company's federal income tax returns for the tax years from 2006 (inception) forward remain subject to examination by the Internal Revenue Service. The Company's state income tax returns for the same period remain subject to examination by the various state taxing authorities.

During 2016, 2015, and 2014, the Company made state and local income tax payments of $340, $303, and an immaterial amount, respectively.

There were no uncertain tax positions as of December 31, 2016 or 2015, and the Company has not currently accrued interest or penalties. If the accrual of interest or penalties becomes appropriate, the Company will record an accrual as part of its income tax provision.

18. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

Changes in accumulated other comprehensive income (loss), net of tax, for the year ended December 31, 2016 and 2015 consisted of the following:

		Postretirement Benefit Plan and Other Employee Benefit Obligations		Accumulated Other Comprehensive Income(Loss)
Balance as of December 31, 2014	$	(3,741)	$	(3,741)
Amounts reclassified from accumulated other comprehensive income (loss)		256		256
Current period change		1,602		1,602
Balance as of December 31, 2015		(1,883)		(1,883)
Amounts reclassified from accumulated other comprehensive income (loss)		**308**		**308**
Current period change		**15**		**15**
Balance as of December 31, 2016	**$**	**(1,560)**	**$**	**(1,560)**

The following is a summary of reclassifications out of accumulated other comprehensive income for the years ended December 31, 2016, 2015 and 2014:

Details about Accumulated Other Comprehensive Income (Loss) Components	Affected Line Item in the Statement Where Net Income (Loss) Is Presented	Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) For the Years Ended December 31,		
		2016	2015	2014
Amortization of prior service cost associated with postretirement benefit plan and other employee benefit obligations	Cost of Coal Sales	**(409)**	(419)	(104)
Amortization of net actuarial gain associated with other employee benefit obligations	Cost of Coal Sales	**101**	—	—
		(308)	(419)	(104)
Income taxes		**—**	163	—
Total reclassifications		**$ (308)**	$ (256)	$ (104)

19. EMPLOYEE BENEFIT PLANS

Defined Contribution Plan

The Company offers a 401(k) savings plan for all employees, whereby the Company matches voluntary contributions up to specified levels. The costs included in the consolidated statements of operations totaled $1,984, $2,689, and $3,034, for the years ended December 31, 2016, 2015, and 2014, respectively.

Postretirement Medical Cost Reimbursement Plan

The Company provides certain health care benefits, including the reimbursement of a portion of out-of-pocket costs associated with insurance coverage, to qualifying salaried and hourly retirees and their dependents. Plan coverage for reimbursements is provided to future hourly and salaried retirees in accordance with the plan document. The Company's funding policy with respect to the plan is to fund the cost of all postretirement benefits as they are paid.

The restructuring activities undertaken during 2015, as more fully described in Note 4, "Asset Impairment and Restructuring Charges," reduced the estimated years of future service of the terminated employees and accelerated postretirement benefits for those participants who were eligible. This resulted in the application of curtailment accounting, triggering the immediate recognition of any unamortized gain or loss and the reduction in the projected benefit obligation.

Net periodic postretirement benefit cost included the following components for the years ended December 31, 2016 and 2015:

	December 31,	
	2016	2015
Service cost for benefits earned	**$ 917**	$ 1,216
Interest cost on accumulated postretirement benefit obligation	**171**	122
Amortization of prior service cost	**95**	104
Curtailment gain recognized	**—**	(209)
Net periodic postretirement cost	**$ 1,183**	$ 1,233

Amounts recognized in accumulated other comprehensive loss are as follows:

	December 31,	
	2016	2015
Net actuarial (gain) loss	$ 207	$ (38)
Prior service cost	555	650
Total recognized in accumulated other comprehensive loss	$ 762	$ 612

The estimated net actuarial gain and prior service cost that will be amortized from accumulated other comprehensive loss into net periodic benefit cost during the year ending December 31, 2017 are zero and $95, respectively.

The following table sets forth changes in benefit obligation and plan assets for the years ended December 31, 2016 and 2015 and the funded status of the plan reconciled with the amounts reported in the Company's consolidated financial statements at December 31, 2016 and 2015:

	2016	2015
Change in Benefit Obligations		
Benefit obligation at January 1	$ 4,229	$ 3,367
Service cost	917	1,216
Interest cost	171	122
Plan amendment	—	—
Plan curtailment	—	(275)
Benefits paid	(285)	(39)
Actuarial loss (gain)	246	(162)
Benefit obligation at December 31	5,278	4,229
Change in Plan Assets		
Value of plan assets at January 1	—	—
Employer contributions	285	39
Benefits paid	(285)	(39)
Value of plan assets at December 31	—	—
Funded status at December 31	$ 5,278	$ 4,229
Amounts Recognized in Balance Sheet		
Current liability	$ 470	$ 316
Non-current liability	4,808	3,913
	$ 5,278	$ 4,229
Amounts Recognized in Accumulated Other Comprehensive Loss		
Prior service cost for period	$ —	$ —
Net actuarial loss (gain) arising during year	246	(162)
Amortization:		
Prior service cost	(95)	(170)
Total recognized in other comprehensive loss	$ 151	$ (332)
Weighted Average Assumptions to Determine Benefit Obligation		
Discount rate	3.93%	4.21%
Rate of compensation increase	N/A	N/A
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost		
Discount rate	4.21%	3.73%
Expected return on plan assets	N/A	N/A

Estimated future benefit payments, which reflect expected future service, as of December 31, 2016 are as follows:

2017	$ 470
2018	430
2019	470
2020	537
2021	594
2022–2026	3,689
Total	$ 6,190

The following presents information about the assumed health care cost trend rate:

	Year Ended December 31,	
	2016	2015
Health care cost trend rate assumed for next year	**6.83%**	7.10%
Rate to which the cost trend is assumed to decline (ultimate trend rate)	**4.50%**	4.50%
Year the rate reaches the ultimate trend rate	**2038**	2027

20. EQUITY AWARDS

The primary stock-based compensation tool used by the Company for its employee base is through awards of restricted stock. The majority of restricted stock awards generally cliff vest after one to three years of service. The fair value of restricted stock is equal to the fair market value of our common stock at the date of grant and is amortized to expense ratably over the vesting period, net of forfeitures.

Information regarding restricted shares activity and weighted-average grant-date fair value follows for the year ended December 31, 2016:

	Restricted Shares	
	Shares	Weighted-Average Grant-Date Fair Value
Outstanding at January 1, 2016	63,000	$ 4.01
Granted	—	—
Vested	(30,000)	5.65
Forfeited	(10,000)	5.65
Outstanding at December 31, 2016	23,000	1.15

The total fair value of restricted stock awards granted and vested during the year ended December 31, 2016 was $0 and $35, respectively.

Unearned compensation of $12 will be recognized related to the outstanding restricted shares that are expected to vest. The expense is expected to be recognized over a weighted average period of 0.5 years. During the years ended December 31, 2016 and 2015, the Company reversed $55 and $137, respectively, of previously recognized compensation expense due to a change in the estimated forfeiture rate from 0% to 100% on certain non-vested restricted stock grants. The Company recognized expense (income) of ($19), $145, and $(74) related to restricted shares for the years ended December 31, 2016, 2015, and 2014, respectively.

21. COMMITMENTS AND CONTINGENCIES

The Company is subject to various market, operational, financial, regulatory, and legislative risks. Numerous federal, state, and local governmental permits and approvals are required for mining operations. Federal and state regulations require regular monitoring of mines and other facilities to document compliance. Monetary penalties of $1,008 and $901 related to Mine Safety and Health Administration (MSHA) fines were accrued in the results of operations for the years ended December 31, 2016 and 2015, respectively.

The Company is involved from time to time in various legal matters arising in the ordinary course of business. In the opinion of management, the resolution of these matters will not have a material adverse effect on the Company's consolidated cash flows, results of operations or financial condition.

Litigation

On July 20, 2016, the Company was notified by an Assistant U. S. Attorney for the Western District of Kentucky of an investigation into potential charges against Armstrong Coal Company, Inc., a wholly-owned subsidiary of the Company (Armstrong Coal Company), and one or more of its current and former employees arising from alleged inaccurate respirable dust sampling at certain of the Company's underground mines. In November 2016, seven current and former Armstrong Coal Company employees received individual target letters from the Assistant U.S. Attorney. In January 2014, MSHA issued a 104(d) citation to the Parkway underground mine related to inaccurate respirable dust sampling, which the Company has challenged. In addition, a Parkway underground mine employee was terminated. The impact of any charges against the Company or its current and former employees cannot be determined at this time, and the Company intends to vigorously defend any such charges should they be pursued.

Claim of Event of Default by Bondholders

On December 30, 2016, Rhino Resource Partners Holdings, LLC (Rhino Holdings), an entity wholly-owned by Yorktown, together with Rhino Resource Partners LP (Rhino), Royal Energy Resources, Inc. (Royal), and Rhino GP LLC (Rhino GP) entered into a put and call option agreement whereby Rhino received a call option, and Rhino Holdings received a put option, on all of the outstanding Company stock currently held by Yorktown (the Option), the majority owner of the Company's outstanding common stock, under certain circumstances. The Option provides that Rhino can exercise the Option after 60 days following entry of an agreement regarding the restructuring of the Notes, but in no event earlier than January 1, 2018 and no later than December 31, 2019. In exchange for Rhino Holdings granting Rhino the Option to purchase Yorktown's holdings of Armstrong Energy stock, Rhino issued 5.0 million common units to Rhino Holdings upon the execution of the Option.

In connection with entry into the Option by the aforementioned parties, on February 2, 2017, the Company received notice from legal counsel representing certain of the Holders of the Notes that the Holders believe entry into the Option by the third-parties constitutes a Change of Control, as defined in the Indenture governing the Notes, and that an Event of Default occurred, as defined in the Indenture, when the Company failed to offer to purchase the Notes within 30 days following the purported Change of Control. However, counsel for the Holders also advised the Company that the Holders are not currently pursuing remedies under the Indenture related to the alleged Event of Default, but reserve their rights to do so at a future time. In addition, certain of the Company's financing agreements include cross-default or cross-event of default provisions, which, if the aforementioned assertions were proven to be accurate, would result indirectly in an event of default under such financing arrangements.

The Company believes that neither a Change of Control nor an Event of Default as defined in the Indenture has occurred. To that end, the Company has advised legal counsel for the Holders that it disputes the allegations. No further action associated with these claims has been taken to date by the Company or the Holders.

Coal Sales Contracts

The Company has historically sold the majority of its coal under multi-year supply agreements of varying duration. These contracts typically have specific and possibly different volume and pricing arrangements for each year of the agreement, which allows customers to secure a supply for their future needs and provides the Company with greater predictability of sales volume and sales prices. Quantities sold under some of these contracts may vary from year to year within certain limits at the option of the customer or the Company. The remaining terms of the Company's long-term contracts range from one to four years. The Company, via contractual agreements, has committed volumes of sales in 2017 of 5.3 million tons.

Coal Transportation Agreements

The Company is engaged in a lease services agreement with a third party to provide all barge switching, coal loading, tug, hauling, and similar services necessary for the Company's operations. During the term of the agreement, the Company will pay a monthly amount based on the annual volume of tons of coal loaded at the dock facility. The Company incurred $2,535, $3,056, and $3,545 of expense during the years ended December 31, 2016, 2015, and 2014, respectively, associated with the coal transportation agreement.

Off-Balance Sheet Arrangements

In the normal course of business, the Company is a party to certain off-balance sheet arrangements, which are not reflected in the Company's consolidated balance sheets. These arrangements include guarantees and financial instruments with off-balance sheet risk, such as surety bonds and performance bonds. In the Company's past, no claims have been made against these financial instruments. The Company does not expect any material adverse effects on its financial condition, results of operations or cash flows to result from these off-balance sheet arrangements.

Federal and state laws require the Company to secure certain long-term obligations such as mine closure and reclamation costs and other obligations. The Company typically secures these obligations by using surety bonds, an off-balance sheet instrument. The use of surety bonds is less expensive for the Company than the alternative of posting a 100% cash bond. To the extent that surety bonds become unavailable, the Company would seek to secure its reclamation obligations with letters of credit, cash deposits or other suitable forms of collateral. The Company also posts performance bonds to secure our performance of various contractual obligations.

As of December 31, 2016, the Company had approximately $32.2 million in surety bonds outstanding to secure the performance of its reclamation obligations, which were supported by approximately $6.0 million of cash posted as collateral.

22. SUPPLEMENTAL GUARANTOR/NON-GUARANTOR FINANCIAL INFORMATION

In accordance with the indenture governing the Notes, certain wholly-owned subsidiaries of the Company have fully and unconditionally guaranteed the Notes, on a joint and several basis, subject to certain customary release provisions. Separate financial statements and other disclosures concerning the Guarantor Subsidiaries are not presented because management believes that such information is not material to the Holders of the Notes. The following historical financial statement information is provided for the Guarantor Subsidiaries. The non-guarantor subsidiaries are considered to be “minor” as the term is defined in Rule 3-10 of Regulation S-X promulgated by the SEC and the financial position, results of operations, and cash flows are, therefore, included in the condensed financial data of the guarantor subsidiaries.

Supplemental Condensed Consolidating Balance Sheets

	December 31, 2016			
	Parent / Issuer	Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS				
Current assets:				
Cash and cash equivalents	$ —	$ 57,505	$ —	$ 57,505
Accounts receivable	—	13,059	—	13,059
Inventories	—	11,809	—	11,809
Prepaid and other assets	849	1,690	—	2,539
Total current assets	849	84,063	—	84,912
Property, plant, equipment, and mine development, net	9,948	223,818	—	233,766
Investments	—	2,794	—	2,794
Investments in subsidiaries	52,639	—	(52,639)	—
Intercompany receivables	35,096	(35,096)	—	—
Other non-current assets	180	12,503	—	12,683
Total assets	$ 98,712	$ 288,082	$ (52,639)	$ 334,155
LIABILITIES AND STOCKHOLDERS' EQUITY/(DEFICIT)				
Current liabilities:				
Accounts payable	$ 302	$ 16,639	$ —	$ 16,941
Accrued and other liabilities	1,578	10,259	—	11,837
Current portion of capital lease obligations	—	555	—	555
Current maturities of long-term debt	—	8,217	—	8,217
Total current liabilities	1,880	35,670	—	37,550
Long-term debt, less current maturities	191,191	7,849	—	199,040
Long-term obligation to related party	—	147,536	—	147,536
Related-party payables, net	(628)	23,185	—	22,557
Asset retirement obligations	—	14,056	—	14,056
Long-term portion of capital lease obligations	—	—	—	—
Other non-current liabilities	99	7,124	—	7,223
Total liabilities	192,542	235,420	—	427,962
Stockholders' equity/(deficit):				
Armstrong Energy, Inc.'s equity/(deficit)	(93,830)	52,639	(52,639)	(93,830)
Non-controlling interest	—	23	—	23
Total stockholders' equity/(deficit)	(93,830)	52,662	(52,639)	(93,807)
Total liabilities and stockholders' equity/(deficit)	$ 98,712	$ 288,082	$ (52,639)	$ 334,155

	December 31, 2015			
	Parent / Issuer	Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS				
Current assets:				
Cash and cash equivalents	$ —	$ 67,617	$ —	$ 67,617
Accounts receivable	—	14,270	—	14,270
Inventories	—	14,562	—	14,562
Prepaid and other assets	110	1,842	—	1,952
Total current assets	110	98,291	—	98,401
Property, plant, equipment, and mine development, net	10,467	250,931	—	261,398
Investments	—	3,525	—	3,525
Investments in subsidiaries	69,429	—	(69,429)	—
Intercompany receivables	70,347	(70,347)	—	—
Other non-current assets	7,441	9,946	—	17,387
Total assets	$ 157,794	$ 292,346	$ (69,429)	$ 380,711
LIABILITIES AND STOCKHOLDERS' EQUITY/(DEFICIT)				
Current liabilities:				
Accounts payable	$ 177	$ 22,378	$ —	$ 22,555
Accrued and other liabilities	1,771	11,274	—	13,045
Current portion of capital lease obligations	—	1,943	—	1,943
Current maturities of long-term debt	—	8,402	—	8,402
Total current liabilities	1,948	43,997	—	45,945
Long-term debt, less current maturities	195,419	8,089	—	203,508
Long-term obligation to related party	—	128,809	—	128,809
Related-party payables, net	(4,411)	20,824	—	16,413
Asset retirement obligations	—	13,990	—	13,990
Long-term portion of capital lease obligations	—	555	—	555
Other non-current liabilities	142	6,630	—	6,772
Total liabilities	193,098	222,894	—	415,992
Stockholders' equity/(deficit):				
Armstrong Energy, Inc.'s equity/(deficit)	(35,304)	69,429	(69,429)	(35,304)
Non-controlling interest	—	23	—	23
Total stockholders' equity/(deficit)	(35,304)	69,452	(69,429)	(35,281)
Total liabilities and stockholders' equity/(deficit)	$ 157,794	$ 292,346	$ (69,429)	$ 380,711

Supplemental Condensed Consolidated Statements of Operations

	Year Ended December 31, 2016			
	Parent / Issuer	Guarantor Subsidiaries	Eliminations	Consolidated
Revenue	$ —	$ 253,902	$ —	$ 253,902
Costs and expenses:				
Operating costs and expenses	—	207,630	—	207,630
Production royalty to related party	—	7,121	—	7,121
Depreciation, depletion, and amortization	1,212	29,828	—	31,040
Asset retirement obligation expenses	—	1,428	—	1,428
Asset impairment and restructuring charges	—	4,431	—	4,431
Non-cash charge on settlement with Thoroughbred	—	10,542	—	10,542
General and administrative expenses	2,025	11,516	—	13,541
Operating loss	(3,237)	(18,594)	—	(21,831)
Other income (expense):				
Interest expense, net	(25,469)	(8,714)	—	(34,183)
Other, net	(2,792)	93	—	(2,699)
Income from investments in subsidiaries	(16,790)	—	16,790	—
Loss before income taxes	(48,288)	(27,215)	16,790	(58,713)
Income tax provision	—	(117)	—	(117)
Net loss	(48,288)	(27,332)	16,790	(58,830)
Income attributable to non-controlling interests	—	—	—	—
Net loss attributable to common stockholders	$ (48,288)	$ (27,332)	$ 16,790	$ (58,830)

	Year Ended December 31, 2015			
	Parent / Issuer	Guarantor Subsidiaries	Eliminations	Consolidated
Revenue	$ —	$ 360,900	$ —	$ 360,900
Costs and expenses:				
Operating costs and expenses	—	282,903	—	282,903
Production royalty to related party	—	7,879	—	7,879
Depreciation, depletion, and amortization	1,806	45,453	—	47,259
Asset retirement obligation expenses	—	1,966	—	1,966
Asset impairment and restructuring charges	4,450	134,229	—	138,679
General and administrative expenses	1,978	13,835	—	15,813
Operating loss	(8,234)	(125,365)	—	(133,599)
Other income (expense):				
Interest expense, net	(23,901)	(10,784)	—	(34,685)
Other, net	—	5,486	—	5,486
Income from investments in subsidiaries	(130,006)	—	130,006	—
Loss before income taxes	(162,141)	(130,663)	130,006	(162,798)
Income tax provision	—	657	—	657
Net loss	(162,141)	(130,006)	130,006	(162,141)
Income attributable to non-controlling interests	—	—	—	—
Net loss attributable to common stockholders	$ (162,141)	$ (130,006)	$ 130,006	$ (162,141)

	Year Ended December 31, 2014			
	Parent / Issuer	Guarantor Subsidiaries	Eliminations	Consolidated
Revenue	$ —	$ 441,833	$ —	$ 441,833
Costs and expenses:				
Operating costs and expenses	—	362,294	—	362,294
Production royalty to related party	—	8,269	—	8,269
Depreciation, depletion, and amortization	1,910	44,602	—	46,512
Asset retirement obligation expenses	—	1,624	—	1,624
General and administrative expenses	3,814	15,776	—	19,590
Operating (loss) income	(5,724)	9,268	—	3,544
Other income (expense):				
Interest expense, net	(24,476)	(8,658)	—	(33,134)
Other, net	—	758	—	758
Income from investments in subsidiaries	1,368	—	(1,368)	—
(Loss) income before income taxes	(28,832)	1,368	(1,368)	(28,832)
Income taxes	—	—	—	—
Net (loss) income	(28,832)	1,368	(1,368)	(28,832)
Income attributable to non-controlling interests	—	—	—	—
Net (loss) income attributable to common stockholders	$ (28,832)	$ 1,368	$ (1,368)	$ (28,832)

Supplemental Condensed Consolidating Statements of Comprehensive Income (Loss)

	Year Ended December 31, 2016			
	Parent / Issuer	Guarantor Subsidiaries	Eliminations	Consolidated
Net loss	**$ (48,288)**	**$ (27,332)**	**$ 16,790**	**$ (58,830)**
Other comprehensive income (loss):				
Postretirement benefit plan and other employee benefit obligations, net of tax	**—**	**323**	**—**	**323**
Other comprehensive income	**—**	**323**	**—**	**323**
Comprehensive loss	**(48,288)**	**(27,009)**	**16,790**	**(58,507)**
Less: Comprehensive income (loss) attributable to non-controlling interests	—	—	—	—
Comprehensive loss attributable to common stockholders	**$ (48,288)**	**$ (27,009)**	**$ 16,790**	**$ (58,507)**

	Year Ended December 31, 2015			
	Parent / Issuer	Guarantor Subsidiaries	Eliminations	Consolidated
Net loss	$ (162,141)	$ (130,006)	$ 130,006	$ (162,141)
Other comprehensive income (loss):				
Postretirement benefit plan and other employee benefit obligations, net of tax	—	1,858	—	1,858
Other comprehensive income	—	1,858	—	1,858
Comprehensive loss	(162,141)	(128,148)	130,006	(160,283)
Less: Comprehensive income (loss) attributable to non-controlling interests	—	—	—	—
Comprehensive loss attributable to common stockholders	$ (162,141)	$ (128,148)	$ 130,006	$ (160,283)

	Year Ended December 31, 2014			
	Parent / Issuer	Guarantor Subsidiaries	Eliminations	Consolidated
Net (loss) income	$ (28,832)	$ 1,368	$ (1,368)	$ (28,832)
Other comprehensive income (loss):				
Postretirement benefit plan, net of tax	—	(3,004)	—	(3,004)
Other comprehensive loss	—	(3,004)	—	(3,004)
Comprehensive loss	(28,832)	(1,636)	(1,368)	(31,836)
Less: Comprehensive income (loss) attributable to non-controlling interests	—	—	—	—
Comprehensive loss attributable to common stockholders	$ (28,832)	$ (1,636)	$ (1,368)	$ (31,836)

Supplemental Condensed Consolidating Statements of Cash Flows

	Year Ended December 31, 2016		
	Parent / Issuer	Guarantor Subsidiaries	Consolidated
Cash Flows from Operating Activities:			
Net cash (used in) provided by operating activities:	**$ (24,013)**	**$ 27,023**	**$ 3,010**
Cash Flows from Investing Activities:			
Investment in property, plant, equipment, and mine development	**(693)**	**(2,336)**	**(3,029)**
Proceeds from partial disposal of investment in equity affiliate	**—**	**500**	**500**
Net cash used in investing activities	**(693)**	**(1,836)**	**(2,529)**
Cash Flows from Financing Activities:			
Payment on capital lease obligations	**—**	**(1,943)**	**(1,943)**
Payments of long-term debt	**—**	**(8,650)**	**(8,650)**
Transactions with affiliates, net	**24,706**	**(24,706)**	**—**
Net cash provided by (used in) financing activities	**24,706**	**(35,299)**	**(10,593)**
Net change in cash and cash equivalents	**—**	**(10,112)**	**(10,112)**
Cash and cash equivalents, at the beginning of the period	**—**	**67,617**	**67,617**
Cash and cash equivalents, at the end of the period	**$ —**	**$ 57,505**	**$ 57,505**

	Year Ended December 31, 2015		
	Parent / Issuer	Guarantor Subsidiaries	Consolidated
Cash Flows from Operating Activities:			
Net cash (used in) provided by operating activities:	$ (23,152)	$ 59,395	$ 36,243
Cash Flows from Investing Activities:			
Investment in property, plant, equipment, and mine development	(2,074)	(17,731)	(19,805)
Proceeds from sale of fixed assets	—	880	880
Net cash used in investing activities	(2,074)	(16,851)	(18,925)
Cash Flows from Financing Activities:			
Payment on capital lease obligations	—	(2,714)	(2,714)
Payments of long-term debt	—	(6,505)	(6,505)
Transactions with affiliates, net	25,226	(25,226)	—
Net cash provided by (used in) financing activities	25,226	(34,445)	(9,219)
Net change in cash and cash equivalents	—	8,099	8,099
Cash and cash equivalents, at the beginning of the period	—	59,518	59,518
Cash and cash equivalents, at the end of the period	$ —	$ 67,617	$ 67,617

	Year Ended December 31, 2014		
	Parent / Issuer	Guarantor Subsidiaries	Consolidated
Cash Flows from Operating Activities:			
Net cash (used in) provided by operating activities:	$ (27,017)	$ 68,162	$ 41,145
Cash Flows from Investing Activities:			
Investment in property, plant, equipment, and mine development	(1,463)	(22,979)	(24,442)
Proceeds from sale of fixed assets	—	5	5
Net cash used in investing activities	(1,463)	(22,974)	(24,437)
Cash Flows from Financing Activities:			
Payment on capital lease obligations	—	(2,690)	(2,690)
Payments of long-term debt	—	(5,942)	(5,942)
Payment of financing costs and fees	(1,000)	—	(1,000)
Repurchase of employee stock relinquished for tax withholdings	(176)	—	(176)
Proceeds from sale-leaseback	—	986	986
Transactions with affiliates, net	29,656	(29,656)	—
Net cash provided by (used in) financing activities	28,480	(37,302)	(8,822)
Net change in cash and cash equivalents	—	7,886	7,886
Cash and cash equivalents, at the beginning of the period	—	51,632	51,632
Cash and cash equivalents, at the end of the period	$ —	$ 59,518	$ 59,518

23. SUMMARY QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

A summary of the unaudited quarterly results of operations for the years ended December 31, 2016 and 2015 is presented below.

	2016			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter[1]
Revenue	**$ 60,444**	**$ 60,309**	**$ 65,388**	**$ 67,761**
Gross profit	**7,769**	**9,670**	**13,031**	**15,802**
Operating loss	**(5,321)**	**(6,228)**	**(20)**	**(10,262)**
Net loss	**(13,441)**	**(15,002)**	**(9,724)**	**(20,663)**
Net loss attributable to common stockholders	**(13,441)**	**(15,002)**	**(9,724)**	**(20,663)**

	2015			
	First Quarter	Second Quarter[2]	Third Quarter[3]	Fourth Quarter
Revenue	$ 96,335	$ 93,139	$ 89,206	$ 82,220
Gross profit	17,505	22,986	19,363	18,143
Operating (loss) income	(6,906)	5,428	(136,683)	4,562
Net (loss) income	(15,254)	894	(145,786)	(1,995)
Net (loss) income attributable to common stockholders	(15,254)	894	(145,786)	(1,995)

[1] Operating loss for the quarter ended December 31, 2016 includes a non-cash charge on the settlement with Thoroughbred of $10,542.

[2] Operating income for the quarter ended June 30, 2015 includes the refund of $4,482 for a portion of Kentucky sales and use taxes paid on the purchase of certain energy and energy producing fuels for the period of 2008 through 2013.

[3] Operating income for the quarter ended September 30, 2015 includes asset impairment and restructuring charges totaling $138,679.

Exhibit 10.11

SECOND AMENDMENT TO EMPLOYMENT AGREEMENT

This Second Amendment to Employment Agreement ("Second Amendment") is entered into this 17th day of March 2017, by and between Armstrong Energy, Inc. and its subsidiaries ("Employer"), 7733 Forsyth Boulevard, Suite 1625, St. Louis, Missouri 63105 and Jeffrey F. Winnick ("Winnick"), 685 Marshall Avenue, St. Louis, Missouri 63119. Employer and Winnick are sometimes referred to collectively herein as the "Parties."

WHEREAS, the Parties entered into that certain Employment Agreement dated September 1, 2015, which was subsequently amended by the First Amendment to Employment Agreement dated April 22, 2016 (collectively the "Agreement"); and

WHEREAS, the Parties desire to further amend the Agreement to clarify certain conditions arising from a non-renewal of the Agreement within twelve (12) months of an event constituting a Change in Control under Section 5.2 of the Agreement, that such non-renewal under Section 5.2 invokes the Separation Package provisions of Section 6.2 of the Agreement, and to further define Good Reason under Section 5.4 of the Agreement, as set forth herein.

NOW, THEREFORE, in consideration of the premises and mutual covenants herein set forth, the Parties hereto agree as follows:

1. Capitalized terms not defined in this Second Amendment shall have the meanings set forth in the Agreement.

2. The first sentence of Section 5.2 of the Agreement is hereby amended and conformed solely to add the following thereto: "or if Employer or an acquiring entity fails to renew this Agreement within twelve (12) months of an event constituting a Change in Control." For illustrative purposes, the first sentence of Section 5.2 of the Agreement shall read in its entirety as follows (with the text of the foregoing amendment in italicized font):

> 5.2 Change in Control. Upon the occurrence of a "Change in Control," provided Winnick's employment with Employer or an acquiring entity is terminated, other than for Cause, within twelve (12) months of an event constituting a Change in Control, *or if Employer or an acquiring entity fails to renew this Agreement within twelve (12) months of an event constituting a Change in Control.*

3. The final sentence of Section 5.4 of the Agreement is hereby amended and conformed to add designation numerals "(i)" and "(ii)", and to add the following thereto: "or Winnick is required to change his regular work location to a location that is more than 75 miles from his regular work location prior to such change." For illustrative purposes, the final sentence of Section 5.4 shall read in its entirety as follows (with the text of the foregoing amendment in italicized font):

> As used herein, "Good Reason" shall mean *(i)* a material demotion or reduction, without Winnick's consent, in Winnick's duties or compensation*; or (ii) Winnick is required to change his regular work location to a location that is more than 75 miles from his regular work location prior to such change*.

4. The first sentence of Section 6.2 of the Agreement is hereby amended solely to add the phrase "or non-renewal". For illustrative purposes, the first sentence of Section 6.2 shall read in its entirety as follows (with the text of the foregoing amendment in italicized font):

> 6.2 Without Cause; For Good Reason; Change in Control. In the event Employer terminates Winnick's employment without Cause, Winnick terminates his employment for Good Reason, or in the event of a termination *or non-renewal* under Section 5.2 due to a Change in Control, Employer shall:

5. All other terms and conditions of the Agreement not expressly amended herein shall remain in full force and effect.

IN WITNESS WHEREOF, this Second Amendment has been executed and delivered by an authorized representative of the Company and by Winnick as of the date first above written.

ARMSTRONG ENERGY, INC.

/s/ Martin D. Wilson
Martin D. Wilson, President and Chief Executive Officer

/s/ Jeffrey F. Winnick
Jeffrey F. Winnick

Exhibit 10.34

SETTLEMENT AGREEMENT AND RELEASE OF ALL CLAIMS

This SETTLEMENT AGREEMENT AND RELEASE OF ALL CLAIMS (" Agreement") is entered this 29th day of March, 2017 (the "Effective Date") by and between Armstrong Energy, Inc. ("AE"), Armstrong Coal Company, Inc. ("ACC"), Elk Creek GP, LLC ("Elk Creek"), Thoroughfare Mining, LLC ("Thoroughfare"), Western Diamond LLC ("WD"), and Western Land Company, LLC ("WLC", and together with AE, ACC, Thoroughfare, Elk Creek, WD, and any other wholly-owned subsidiary of AE, collectively referred to as the "Armstrong Entities"); and Thoroughbred Holdings GP, LLC ("Thoroughbred Holdings"), Thoroughbred Resources, L.P. ("Thoroughbred"), Western Mineral Development, LLC ("WMD"), and Ceralvo Holdings, LLC ("Ceralvo", and, together with Thoroughbred, WMD and any other wholly-owned subsidiary of Thoroughbred Holdings, the "Thoroughbred Entities") (collectively, the "Parties").

W I T N E S S E T H

WHEREAS, certain Armstrong Entities and Thoroughbred Entities are parties to certain Leases (defined in Section 1 below) governing coal mining properties located in western Kentucky, which, among other matters, require payment of production royalties ("Production Royalties") to certain of the Thoroughbred Entities;

WHEREAS, under the terms of that First Amended and Restated Royalty Deferment and Option Agreement (the "Royalty Agreement") dated August 14, 2014, by and among ACC, Thoroughfare, WD, WL, Thoroughbred, WMD, and Ceralvo, the Armstrong Entities are permitted under certain conditions, in lieu of paying Production Royalties in cash, to convey to the Thoroughbred Entities certain transferable Subject Assets, provided such properties are then leased back to the Armstrong Entities on substantially the terms of the Leases;

WHEREAS, under the terms of the Royalty Agreement, the transfer of interest in the Subject Assets is to close on or before ninety (90) days after the end of the year for which a Deferment Option has been exercised;

WHEREAS, the Thoroughbred Entities disputed various items related to the Royalty Agreement and ASA including but not limited to: (i) the Armstrong Entities' proposed transfer of a 10.95% undivided interest in certain transferable Subject Assets pursuant to the Royalty Agreement to satisfy Production Royalties for calendar year 2016 and prior years; (ii) Armstrong's purported election of the Deferment Option for 2017; (iii) the ASA Fees (defined in Section 1 below) and certain setoffs to the Production Royalties arising from the ASA Fees; and (iv) the Production Royalty Overpayment (defined in Section 1 below) and certain setoffs to the Production Royalties arising from the Production Royalty Overpayment;

WHEREAS, pursuant to Section 3 of the Royalty Agreement, and in consideration of the representations, warranties, releases, and covenants set forth herein, the parties agree that the Armstrong Entities shall increase the proposed transfer of a 10.95% undivided interest in certain transferable Subject Assets by 9.86%, such that the Armstrong Entities will transfer a total 20.81% undivided interest (the "Conveyed Interest") in the transferable Subject Assets, exclusive of certain

non-transferable assets more particularly listed on Exhibit A (the "Excluded Properties") attached hereto (the Subject Assets, excluding the Excluded Properties, referred to herein as the "Conveyed Properties") in satisfaction of all Production Royalties incurred during calendar year 2016 and any underpayment of Production Royalties prior to calendar year 2016;

WHEREAS, upon receipt of the Conveyed Interest, the Thoroughbred Entities will have acquired 100% of the Conveyed Properties from the Armstrong Entities, which will cause the expiration of the term of the Royalty Agreement; and

WHEREAS, the Parties desire to (a) mutually confirm the amount of Conveyed Interest to be conveyed and other terms relating to the conveyance, (b) acknowledge and agree upon the termination of the Royalty Agreement in accordance with its terms, and (c) resolve and settle any and all actual or possible differences, disputes, or claims between them arising under or in any way related to the Royalty Agreement, the ASA, and the Leases as set forth herein.

NOW THEREFORE, for an in consideration of the premises and mutual promises and agreements contained herein, together with other good and valuable consideration, receipt and sufficiency of which is hereby acknowledged, it is mutually agreed as follows:

1. Definitions

a. ASA shall mean that certain Administrative Services Agreement dated October, 11, 2011 between AE, Thoroughbred (formerly known as Armstrong Resource Partners, L.P.,) and Elk Creek.

b. ASA Fees shall have the meaning ascribed in Section 4 of this Agreement.

c. Armstrong Entities shall have the meaning set forth in the opening paragraph of this Agreement.

d. Conveyed Interest shall have the meaning set forth in the fifth recital of this Agreement.

e. Conveyed Properties shall have the meaning set forth in the fifth recital of this Agreement.

f. Deeds of Correction shall mean (1) that certain Deed of Correction by and between ACC, Ceralvo, WD, and WMD with an effective date of May 2, 2016 to correct and amend the Special Warranty Deed of May 2, 2016, which is of record in Deed Book 417, page 436, in the Office of the Ohio County Clerk; and (2) that certain Deed of Correction by and between WD and WMD with an effective date of June 1, 2016 to correct and amend that Special Warranty Deed dated June 1, 2016 of record in Deed Book 415, page 737 in the Office of the Ohio County Clerk.

g. Deferment Option shall have the meaning set forth in the Royalty Agreement.

h. Excluded Properties shall have the meaning set forth the fifth recital of this Agreement.

i. Leases shall mean the Existing Leases defined in the Royalty Agreement.

j. Production Royalties shall have the meaning set forth in the first recital of this Agreement.

k. Production Royalty Overpayment shall have the meaning set forth in Section 5 of this Agreement.

l. Royalty Agreement shall have the meaning set forth in the second recital of this Agreement.

m. Subject Assets shall have the meaning set forth in the Royalty Agreement.

n. Thoroughbred Entities shall have the meaning set forth in the opening paragraph of this Agreement.

o. Thoroughbred Correspondence shall mean (i) the letter dated December 16, 2016 from William T. Gorton III, Esq. of Stites & Harbison PLLC ("Stites") to Martin D. Wilson regarding the First Amended and Restated Royalty Deferment and Option Agreement between Thoroughbred and Armstrong; (ii) the letter dated January 6, 2017 from Charles R. Wesley, IV of Thoroughbred to Martin D. Wilson regarding Armstrong-Thoroughbred Disputes and the attachments thereto; (iii) the letter dated February 15, 2017 from William T. Gorton of Stites to Martin D. Wilson regarding Disputes Related to the First Amended and Restated Royalty Deferment and Option Agreement Response to Recent Armstrong Letters; (iv) the letter dated February 15, 2017 from Charles R. Wesley, IV of Thoroughbred to Martin D. Wilson regarding Armstrong-Thoroughbred Disputes and the attachments thereto; (v) the letter dated March 2, 2017 from Charles R. Wesley, IV of Thoroughbred to Martin D. Wilson regarding Certain Disputes between Thoroughbred and Armstrong; and (vi) the letter dated March 7, 2017 from Charles R. Wesley, IV of Thoroughbred to Martin D. Wilson regarding Certain Disputes between Thoroughbred and Armstrong.

p. Transfer Closing Date shall have the meaning ascribed in Section 2 of this Agreement.

q. Transfer Effective Date shall have the meaning ascribed in Section 2 of this Agreement.

2. Transfer of Conveyed Properties. In consideration of the recitals, representations, warranties, waivers, and covenants set forth herein, and subject to the Thoroughbred Entities' prior execution and delivery of the Deeds of Correction to the Armstrong Entities, on or before March 31, 2017 (the "Transfer Closing Date"), the Armstrong Entities shall cause the Conveyed Interest to be conveyed to WMD by special warranty deeds or assignments of partial lease interests (in accordance with past practices), with an effective date of such conveyance to be retroactive to January 1, 2017 (to the extent not prohibited by law) (the "Transfer Effective Date"). The Armstrong

Entities shall be responsible for the payment of applicable transfer taxes, and the Thoroughbred Entities shall be responsible for payment of all recording fees (in accordance with past practices).

3. Treatment of Leases & Production Royalties. The Parties acknowledge that, upon the transfer of the Conveyed Interest, the Royalty Agreement shall terminate on the Transfer Effective Date, by its own terms, without any further action by any of the Parties. However, to the extent that further action is advisable by either Party's legal counsel or otherwise necessary to terminate the Royalty Agreement subsequent to the Transfer Effective Date, the Parties agree to cooperate to execute any other documents or instrument, or take any further action that may be necessary to terminate or acknowledge termination of the Royalty Agreement. As a result of termination of the Royalty Agreement, all Production Royalties set forth in the Leases shall be paid in accordance with the terms of such Lease from and after January 1, 2017; provided that contemporaneous with the receipt of fully executed documents on the Transfer Closing Date, the Armstrong Entities shall cause to be paid to the Thoroughbred Entities by wire transfer in accordance with the wire instructions set forth in Exhibit B, all unpaid Production Royalties due and payable pursuant to the Leases from January 1, 2017 through the Transfer Closing Date totaling $2,651,167.29 for January 2017 and February 2017 (the "2017 YTD Payment"). Upon request of any Party, the other Parties each agree to cooperate to execute any modification of the Leases (and the underlying short forms thereof) to properly reflect the 100% undivided interest held by the respective Thoroughbred Entities and to cause those Armstrong Entities who previously were joint owners to be removed as lessors, along with such ancillary changes needed to properly incorporate such changes.

4. Treatment of ASA. The Parties acknowledge that by separate agreement dated November 11, 2016, the ASA was terminated effective December 31, 2016, with the parties thereto retaining all rights and obligations relating to periods prior to such termination, including payment of any service fees for the period up to and including December 31, 2016. The Armstrong Entities subsequently asserted that certain administrative services fees in the amount of $314,000.00 (the "ASA Fees") were due and outstanding for the period prior to termination of the ASA, which the Thoroughbred Entities dispute. As further consideration of the recitals, representations warranties, waivers, and covenants set forth in this Agreement, the Armstrong Entities waive and release the ASA Fees.

5. Treatment of Certain Production Royalty Overpayments. The Armstrong Entities previously advised the Thoroughbred Entities of an alleged overpayment of $2,217,054.83 for Production Royalties paid prior to September 30, 2016 due to payment made on properties other than the Subject Assets (the "Production Royalty Overpayment") and proposed to deduct such overpayment from Production Royalties incurred during calendar year 2016. As further consideration of the recitals, representations, warranties, waivers, and covenants set forth in this Agreement, the Parties acknowledge and agree that the Production Royalty Overpayment is part of the consideration for the conveyance of the Conveyed Interest made pursuant to Section 2 of this Agreement, and that neither the Armstrong Entities nor the Thoroughbred Entities are liable to the other with regard to any payment or reimbursement in connection with the alleged Production Royalty Overpayment.

6. Representations and Warranties of the Parties. Each Party represents and warrants as follows:

(a) Each has the power and authority to execute, deliver and carry out the terms and provisions of this Agreement and to consummate the transactions contemplated hereby, and has taken all necessary action to authorize the execution, delivery and performance of this Agreement and the transactions contemplated hereby.

(b) This Agreement has been duly and validly authorized, executed and delivered by each Party, and constitutes a valid and binding agreement of such Party enforceable in accordance with its terms.

(c) This Agreement, including the consideration herein, has been determined based upon honest and arms-length settlement negotiations by and among the Parties or through their respective counsel, all such Parties having full and complete access to the information which they thought to be relevant in determining whether to sign this Agreement.

(d) Neither Party has assigned any claims, demands, actions or causes of action that have or could be asserted against the other Parties released hereunder, and agrees to indemnify and defend the other Parties from any such assignment, if any.

(e) As of the Effective Date, there are no known defaults under the Leases and, except for the accrual of Production Royalties from and after January 1, 2017, there are no other amounts known to be due or owing under the Leases.

7. Waivers and Releases. The waivers and releases described herein shall become effective upon transfer of the Conveyed Interest to the Thoroughbred Entities and receipt by the Thoroughbred Entities of the 2017 YTD Payment:

(a) The Thoroughbred Entities, in consideration of the mutual promises and covenants made in this Agreement, on their own behalf and on behalf of their heirs, successors, assigns, executors, officers, agents, directors, officials, trustees, administrators, guardians, agents, predecessors, beneficiaries, representatives, attorneys, consultants, family members, and anyone acting or purporting to act on their respective behalf either now or in the future hereby release, compromise, surrender and forever discharge the Armstrong Entities and their affiliates, including, without limitation, present and former subsidiaries, parents, and related entities, and their employees, directors, officers, agents, stockholders, predecessors, successors, attorneys, insurers, advisors (including, without limitation, Ernst & Young LLP and Duff & Phelps LLC), and anyone acting or purporting to act on their respective behalf from any and all actions, suits, debts, dues, sums of money, accounts, controversies, agreements, promises, trespasses, damages, fees (including but not limited to attorneys' fees), costs, expenses, claims and demands and choses of action, known or unknown, direct or indirect, ascertained or not ascertained, liquidated or unliquidated, contingent or not, suspected or unsuspected, matured or unmatured, whether arising in law, admiralty, equity or otherwise which the Thoroughbred Entities (i) ever had, now have or hereafter can, shall, or may have relating to, directly or indirectly, the Royalty Agreement or the ASA; and (ii) ever had, or now have, or may have that arise under or are related, either directly or indirectly, to (a) the payment of

royalties or related sums of money due under the Leases for coal sold prior to the Transfer Effective Date; (b) the administration of the Leases by the Armstrong Entities prior to the Transfer Effective Date; (c) lost or wasted coal for mining practices and operational decisions made by Armstrong prior to the Effective Date; and (d) any other demands, claims, or assertions set forth in the Thoroughbred Correspondence, in any venue, jurisdiction, or forum at any time.

(b) The Armstrong Entities, in consideration of the mutual promises and covenants made in this Agreement, on their own behalf and on behalf of their heirs, successors, assigns, executors, officers, agents, directors, officials, trustees, administrators, guardians, agents, predecessors, beneficiaries, representatives, attorneys, consultants, family members, and anyone acting or purporting to act on their respective behalf either now or in the future hereby release, compromise, surrender and forever discharge the Thoroughbred Entities and their affiliates, including, without limitation, present and former subsidiaries, parents, and related entities, and their employees, directors, officers, agents, stockholders, predecessors, successors, attorneys, insurers, advisors and anyone acting or purporting to act on their respective behalf from any and all actions, suits, debts, dues, sums of money, accounts, controversies, agreements, promises, trespasses, damages, fees (including but not limited to attorneys' fees), costs, expenses, claims and demands and choses of action, known or unknown, direct or indirect, ascertained or not ascertained, liquidated or unliquidated, contingent or not, suspected or unsuspected, matured or unmatured, whether arising in law, admiralty, equity or otherwise which the Armstrong Entities (i) ever had, now have or hereafter can, shall, or may have relating to, directly or indirectly, the Royalty Agreement or the ASA; (ii) ever had, or now have, or may have that arise under or are related, either directly or indirectly, to the payment of royalties or related sums of money due under the Leases prior to the Transfer Effective Date, in any venue, jurisdiction, or forum at any time.

(c) The Thoroughbred Entities and the Armstrong Entities, and each of them, shall not assist or encourage any person to take any action (including any regulatory or administrative action) that would be inconsistent with the foregoing releases and the terms and provisions of this Agreement, nor shall the Parties encourage or assist any person to take against any person released by this Agreement any action (including any regulatory, criminal or administrative action) that would be inconsistent with the foregoing releases and the terms and provisions of this Agreement, provided that this provision does not affect any obligation to respond to any valid and enforceable court order or subpoena.

8. **Non-Admission of Liability** The Parties agree that the execution of this Agreement is done solely for the purposes of compromise of one or more disputed claims, and does not constitute, and should not be construed as, an admission of liability, wrongdoing, fault, judgment or concession or as evidence with respect thereto by any Party.

9. **Legal Costs & Attorney's Fees.** By execution of this Agreement, the Parties expressly warrant that all claims for costs, attorneys' fees, and expenses of counsel and experts have been or will be paid or otherwise resolved by the Party incurring such expense and that no such claims remain pending.

10. **No Waiver.** Any waiver by any Party hereto of a breach of any provision of this Agreement shall not operate as or be construed to be a waiver of any other breach of such provision or of any breach of any other provision of this Agreement. The failure of a Party hereto to insist upon strict adherence to any term of this Agreement on one or more occasions shall not be considered a waiver or deprive that Party of the right thereafter to insist upon strict adherence to that term or any other term of this Agreement.

11. **Entire Agreement; Amendments.** This Agreement contains the entire understanding of the Parties with respect to its subject matter. There are no restrictions, agreements, promises, representations, warranties, covenants, or undertakings other than those expressly set forth herein. This Agreement may be amended only by a written instrument duly executed by each of the Parties or their respective successors or assigns.

12. **Law Governing Agreement**. This Agreement shall be governed by and construed by the laws of the Commonwealth of Kentucky, excepting choice of law provisions.

13. **Headings; Construction; Severability.** The section headings contained in this Agreement are for reference purposes only and shall not affect in any way the meaning or interpretation of this Agreement. The Parties agree that, in all cases, the language of this Agreement shall be construed as a whole, according to its fair meaning, and not strictly for or against either of the Parties. In the event that one or more of the provisions contained in this Agreement shall, for any reason, be held to be invalid, illegal, or unenforceable in any respect, the remainder of the Agreement shall be enforceable.

14. **Counterparts.** This Agreement may be executed in counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same Agreement.

15. **Facsimile; Electronic Mail.** This Agreement may be executed and delivered via facsimile or electronic mail, with a copy sent to each Party. Any Party delivering this Agreement by fax or electronic mail initially shall provide an original counterpart to all other Parties within five (5) days delivering thereafter.

[*Remainder of Page Intentionally Blank*]

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement by their duly authorized representatives, as of the Effective Date set forth above.

Armstrong Energy, Inc.

By: /s/ Martin D. Wilson

Its: President & CEO

Armstrong Coal Company, Inc.

By: /s/ Martin D. Wilson

Its: President

Elk Creek GP, LLC

By: /s/ Martin D. Wilson

Its: CEO

Thoroughfare Mining, LLC

By: /s/ Martin D. Wilson

Its: President & CEO

Western Diamond LLC

By: /s/ Martin D. Wilson

Its: President & CFO

Western Land Company, LLC

By: /s/ Martin D. Wilson

Its: Manager

Thoroughbred Holdings GP, LLC

By: /s/ Charles R. Wesley, IV

Its: CEO

Thoroughbred Resources, L.P.

By: /s/ Charles R. Wesley, IV

Its: CEO of Thoroughbred Holdings GP, LLC, its sole General Partner

Western Mineral Development, LLC

By: /s/ Charles R. Wesley, IV

Its: President

Ceralvo Holdings, LLC

By: /s/ Charles R. Wesley, IV

Its: President

EXHIBIT A

Excluded Properties

(i) The Partial Assignment of Coal Mining Lease from Central States Coal Reserves of Kentucky, LLC to Western Diamond LLC dated September 19, 2006, of record in Deed Book 363, page 428, in the records of Ohio County, Kentucky;

(ii) The Corporation Special Warranty Deed from Central States Coal Reserves of Kentucky, LLC and Beaver Dam Coal Company to Western Diamond LLC, dated September 19, 2006, of record in Deed Book 363, page 414, in the records of Ohio County, Kentucky;

(iii) Property described in that Quitclaim Deed between Western Mineral Development, LLC and Western Land Company, LLC dated March 30, 2012, which is of record in Deed Book 557 page 692 in the records of Muhlenberg County, Kentucky;

(iv) The Partial Assignment and Assumption of Surface and Mineral Leasehold Estate from Central States Coal Reserves of Kentucky, LLC to Western Land Company, LLC, dated November 20, 2006, of record in Deed Book 365, page 57, in the Office of the Muhlenberg County Clerk; and

(v) Property described in that Quitclaim Deed between Western Mineral Development, LLC and Western Land Company, LLC dated March 30, 2012, which is of record in Deed Book 557 page 701 in the records of Muhlenberg County, Kentucky.

EXHIBIT B

Wire Transfer Instructions

U.S. Bank N.A ABA# 102000021
Account# 103690843356

Business Address:
Thoroughbred Resources, LP
201 Steele St Suite #2B
Denver, CO 80206

Exhibit 21.1

SUBSIDIARIES

Armstrong Energy, Inc.'s principal subsidiaries as of December 31, 2016 are listed below. All other subsidiaries, if considered in the aggregate as a single subsidiary, would not constitute a significant subsidiary.

Subsidiary Name	Jurisdiction of Incorporation
Armstrong Energy Holdings, Inc.	DE
Armstrong Coal Company, Inc.	DE
Western Diamond LLC	NV
Western Land Company, LLC	KY
Elk Creek GP, LLC	DE
Thoroughfare Mining, LLC	DE
Armstrong Coal Sales, LLC	DE

Exhibit 23.1

CONSENT OF WEIR INTERNATIONAL, INC.

Weir International, Inc. ("WEIR") hereby consents to the use of its name in connection with references to its involvement in the reserve and resource estimates included in WEIR's March 22, 2017 Reserve and Resource Study (the "Report") in connection with Armstrong Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2016 (the "Form 10-K"), and any amendments thereto. WEIR hereby further consents to the use of the Report, or portions thereof, and to the inclusion or incorporation by reference of information derived from the Report in the Form 10-K.

We further wish to advise that Weir International, Inc. was not employed on a contingent basis and that at the time of preparation of our report, as well as at present, neither Weir International, Inc. nor any of its employees had or now has a substantial interest in Armstrong Energy, Inc. or any of its subsidiaries.

Respectfully submitted:

By: /s/ Dennis N. Kostic
Name: Dennis N. Kostic
Title: President and CEO

Date: March 31, 2017

Exhibit 31.1

CERTIFICATION

I, Martin D. Wilson, certify that:

1. I have reviewed this Annual Report on Form 10-K of Armstrong Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a–15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

March 31, 2017

By: /s/ Martin D. Wilson
Martin D. Wilson
President and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATION

I, Jeffrey F. Winnick, certify that:

1. I have reviewed this Annual Report on Form 10-K of Armstrong Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a–15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 31, 2017

By: /s/ Jeffrey F. Winnick
Jeffrey F. Winnick
Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, Martin D. Wilson, President and Chief Executive Officer of Armstrong Energy, Inc. (the "Company"), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that:

1. The Annual Report on Form 10-K of the Company for the year ended December 31, 2016 (the "Report") fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934 (15 U.S.C. 78m); and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Martin D. Wilson

Martin D. Wilson
President and Chief Executive Officer
(Principal Executive Officer)

March 31, 2017

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, Jeffrey F. Winnick, Vice President and Chief Financial Officer of Armstrong Energy, Inc. (the "Company"), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that:

1. The Annual Report on Form 10-K of the Company for the year ended December 31, 2016 (the "Report") fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934 (15 U.S.C. 78m); and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Jeffrey F. Winnick

Jeffrey F. Winnick
Vice President and Chief Financial Officer
(Principal Financial Officer)

March 31, 2017

Exhibit 95.1

Mine Safety and Health Administration (MSHA) Safety Data

Armstrong Energy, Inc.'s mining operations are subject to regulations issued by MSHA under the U.S. Federal Mine Safety and Health Act of 1977 (the Mine Act). MSHA inspects our mines on a regular basis and issues various citations and orders when it believes a violation has occurred under the Mine Act. Whenever MSHA issues a citation or order, it also generally proposes a civil penalty, or fine, related to the alleged violation. Citations or orders can be contested and appealed, and as part of that process, are often reduced in severity and amount, and are sometimes dismissed. The number of citations, orders and proposed assessments varies depending on the size and type (underground or surface) of the mine, among other factors.

The following disclosures have been provided pursuant to Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Act).

Mine Safety Data. The following provides additional information about references used in the table below to describe the categories of violations, orders or citations issued by MSHA under the Mine Act:

- **Section 104 S&S Citations:** Citations issued by MSHA under Section 104(a) of the Mine Act for violations of health or safety standards that could significantly and substantially contribute to a serious injury if left unabated.
- **Section 104(b) Orders:** Orders issued under Section 104(b) of the Mine Act, which represent a failure to abate a citation under Section 104(a) within the period prescribed by MSHA. This results in an order of immediate withdrawal from the area of the mine affected by the condition until MSHA determines that the violation has been abated.
- **Section 104(d) Citations and Orders:** Citations and orders issued by MSHA under Section 104(d) of the Mine Act for unwarrantable failure to comply with mandatory health or safety standards. These types of violations could significantly and substantially contribute to a serious injury; however, the conditions do not cause imminent danger (refer to discussion of imminent danger orders below).
- **Section 104(e) Notices:** Notices issued by MSHA under Section 104(e) of the Mine Act for an alleged pattern of violations of mandatory health or safety standards that could significantly and substantially contribute to mine health or safety hazards.
- **Section 110(b)(2) Violations:** Flagrant violations identified by MSHA under Section 110(b)(2) of the Mine Act. The term flagrant with respect to a violation is defined as "a reckless or repeated failure to make reasonable efforts to eliminate a known violation of a mandatory health or safety standard that substantially and proximately caused, or reasonably could have expected to cause, death or serious bodily injury."
- **Section 107(a) Orders:** Orders issued by MSHA under Section 107(a) of the Mine Act for situations in which MSHA determined an imminent danger existed. Orders issued under Section 107(a) of the Mine Act require the operator of the mine to cause all persons (except authorized persons) to be withdrawn from the mine until the imminent danger and the conditions that caused such imminent danger cease to exist.

The following table details the violations, citations and orders issued to us by MSHA during the year ended December 31, 2016, not taking into account any changes to the severity or amount of such citations or orders after assessment:

Mine[1]	MSHA ID	Section 104 S&S Citations (#)	Section 104(b) Orders (#)	Section 104(d) Citations and Orders (#)	Section 110 (b)(2) Violations (#)	Section 107(a) Orders (#)	Total Dollar Value of Proposed MSHA Assessments (in thousands) ($)	Total Number of Mining Related Fatalities (#)	Received Notice of Pattern of Violations Under Section 104(e) (yes/no)	Received Notice of Potential to Have Pattern of Violations Under Section 104(e) (yes/no)
Midway	15-19217	0	0	0	0	0	0.3	0	No	No
Parkway Underground	15-19358	38	0	3	0	0	253.2	0	No	No
East Fork	15-19407	0	0	0	0	0	0.0	0	No	No
Equality Boot	15-19344	3	0	0	0	0	3.8	0	No	No
Lewis Creek	15-19511	1	0	0	0	0	0.9	0	No	No
Kronos Underground	15-19535	78	0	0	0	0	206.7	0	No	No
Lewis Creek Underground	15-19669	0	0	0	0	0	0.0	0	No	No
Survant Underground	15-19744	22	0	0	0	0	13.4	0	No	No
Midway Prep.	15-19165	0	0	0	0	0	0.2	0	No	No
Parkway Prep.	15-19356	1	0	0	0	0	0.7	0	No	No
Armstrong Prep. & Dock	15-19345	5	0	0	0	0	2.3	0	No	No

(1) The table does not include the following: (i) facilities which have been idled or closed unless they received a citation or order issued by MSHA; and (ii) permitted mining sites where we have not begun operations and therefore have not received any citations.

Pending Legal Actions. The table below provides a summary of legal actions pending before the Federal Mine Safety and Health Review Commission (the Commission) as of December 31, 2016, as well as the aggregate number of legal actions instituted and resolved during the year ended December 31, 2016. Each legal action is assigned a docket number by the Commission and may have as its subject matter one or more citations, orders, penalties or complaints. The Commission is an independent adjudicative agency established by the Mine Act that provides administrative trial and appellate review of legal disputes arising under the Mine Act. These cases may involve, among other questions, challenges by operators to citations, orders and penalties they have received from MSHA, or complaints of discrimination by miners under Section 105 of the Mine Act.

The following provides additional information of the types of proceedings that may be brought before the Commission:

- **Contest Proceedings** – A contest proceeding may be filed by an operator to challenge the issuance of a citation or order issued by MSHA.
- **Civil Penalty Proceedings** – A civil penalty proceeding may be filed by an operator to challenge a civil penalty MSHA has proposed for a violation contained in a citation or order. The validity of the citation may be challenged in this proceeding, as well.
- **Discrimination Proceedings** – Involves a miner's allegation that he or she has suffered adverse employment action because he or she engaged in activity protected under the Mine Act, such as making a safety complaint. Also includes temporary reinstatement proceedings involving cases in which a miner has filed a complaint with MSHA stating that he or she has suffered discrimination and the miner has lost his or her position.
- **Compensation Proceedings** – A compensation proceeding may be filed by miners entitled to compensation when a mine is closed by certain closure orders issued by MSHA. The purpose of the proceeding is to determine the amount of compensation, if any, due to miners idled by the orders.
- **Temporary Relief** – Applications for temporary relief are applications filed under section 105(b)(2) of the Mine Act for temporary relief from any modification or termination of any order.
- **Appeals** – An appeal may be filed by an operator to challenge judges' decisions or orders to the Commission, including petitions for discretionary review and review by the Commission on its own motion.

Mine	MSHA ID	Legal Actions Pending as of Last Day of Period (#)	Contests of Citations and Orders (#)	Contests of Proposed Penalties (#)	Complaints for Compensation (#)	Complaints of Discharge, Discrimination, or Interference (#)	Applications for Temporary Relief (#)	Appeals of Judges' Decisions or Orders (#)	Legal Actions Initiated During Period (#)	Legal Actions Resolved During Period (#)
Midway	15-19217	1	0	1	0	0	0	0	1	4
Parkway Underground	15-19358	23	0	14	0	9	0	0	22	18
East Fork	15-19407	0	0	0	0	0	0	0	0	0
Equality Boot	15-19344	1	0	1	0	0	0	0	5	7
Lewis Creek	15-19511	1	0	1	0	0	0	0	1	0
Kronos Underground	15-19535	9	0	9	0	0	0	0	13	15
Lewis Creek Underground	15-19669	0	0	0	0	0	0	0	0	1
Survant Underground	15-19744	0	0	0	0	0	0	0	3	5
Midway Prep.	15-19165	1	0	1	0	0	0	0	1	0
Parkway Prep.	15-19356	0	0	0	0	0	0	0	2	3
Armstrong Prep. & Dock	15-19345	1	0	0	0	1	0	0	1	2
Big Run Underground	15-18552	0	0	0	0	0	0	0	0	0

Exhibit 99.3

ARMSTRONG ENERGY, INC.

CHARTER OF THE NOMINATING AND CORPORATE GOVERNANCE COMMITTEE
(Effective May 10, 2016)

I. MEMBERSHIP

The Nominating and Corporate Governance Committee (the "Committee") of the board of directors (the "Board") of Armstrong Energy, Inc. (the "Company") shall consist of three or more directors. Each member of the Committee shall be independent in accordance with the rules of the NASDAQ stock market.

The members of the Committee shall be appointed by the Board. The members of the Committee shall serve for such term or terms as the Board may determine or until earlier resignation or death. The Board may remove any member from the Committee at any time with or without cause.

II. PURPOSE

The purpose of the Committee is to carry out the responsibilities delegated by the Board relating to the Company's director nominations process and procedures, developing and maintaining the Company's corporate governance policies and any related matters required by the federal securities laws.

III. DUTIES AND RESPONSIBILITIES

The Committee shall have the following authority and responsibilities:

- To determine the qualifications, qualities, skills, and other expertise required to be a director and to develop, and recommend to the Board for its approval, criteria to be considered in selecting nominees for director (the "Director Criteria").
- To identify and screen individuals qualified to become members of the Board, consistent with the Director Criteria. The Committee shall consider any director candidates recommended by the Company's stockholders pursuant to the procedures described in the Company's proxy statement. The Committee shall also consider any nominations of director candidates validly made by stockholders in accordance with applicable laws, rules and regulations and the provisions of the Company's charter documents.
- To make recommendations to the Board regarding the selection and approval of the nominees for director to be submitted to a stockholder vote at the annual meeting of stockholders.
- To develop and recommend to the Board a set of corporate guidelines applicable to the Company, to review these principles at least once a year and to recommend any

changes to the Board, and to oversee the Company's corporate governance practices, including reviewing and recommending to the Board for approval any changes to the other documents and policies in the Company's corporate governance framework, including its certificate of incorporation and bylaws.

- To develop, subject to approval by the Board, a process for an annual evaluation of the Board and its committees and to oversee the conduct of this annual evaluation.

- To review the Board's committee structure and composition and to make recommendations to the Board regarding the appointment of directors to serve as members of each committee and committee chairpersons annually.

- If a vacancy on the Board and/or any Board committee occurs, to identify and make recommendations to the Board regarding the selection and approval of candidates to fill such vacancy either by election by stockholders or appointment by the Board.

- To develop and recommend to the Board for approval standards for determining whether a director has a relationship with the Company that would impair its independence.

- To review and discuss with management the disclosure regarding the operations of the Committee and director independence, and to recommend that this disclosure be included in the Company's proxy statement or annual report on Form I 0-K, as applicable.

- To monitor compliance with the Company's Code of Business Conduct and Ethics (the "Code"), to investigate any alleged breach or violation of the Code and to enforce the provisions of the Code.

- To develop and recommend to the Board for approval a CEO succession plan (the "Succession Plan"), to review the Succession Plan periodically with the CEO and recommend to the Board any changes and any candidates for succession under the Succession Plan.

- To develop and oversee a Company orientation program for new directors and a continuing education program for current directors.

IV. OUTSIDE ADVISORS

The Committee shall have the authority, in its sole discretion, to select, retain and obtain the advice of a director search firm as necessary to assist with the execution of its duties and responsibilities as set forth in this Charter. The Committee shall set the compensation, and oversee the work, of the director search firm. The Committee shall have the authority, in its sole discretion, to retain and obtain the advice and assistance of outside counsel and such other advisors as it deems necessary to fulfill its duties and responsibilities under this Charter. The Committee shall set the compensation, and oversee the work, of its outside counsel and other advisors. The Committee shall receive appropriate funding from the Company, as determined by the Committee in its capacity as a

committee of the Board, for the payment of compensation to its compensation consultants, outside counsel and any other advisors.

The director search firm, outside counsel and any other advisors retained by the Committee shall be independent as determined in the discretion of the Committee.

V. STRUCTURE AND OPERATIONS

The Board shall designate a member of the Committee as the chairperson. The Committee shall meet at least quarterly, and at such times and places as it deems necessary to fulfill its responsibilities. The Committee shall report regularly to the Board regarding its actions and make recommendations to the Board as appropriate. The Committee is governed by the same rules regarding meetings (including meetings in person or by telephone or other similar communications equipment), action without meetings, notice, waiver of notice, and quorum and voting requirements as are applicable to the Board.

The Committee shall review this Charter at least annually and recommend any proposed changes to the Board for approval.

VI. DELEGATION OF AUTHORITY

The Committee shall have the authority to delegate any of its responsibilities, along with the authority to take action in relation to such responsibilities, to one or more subcommittees as the Committee may deem appropriate in its sole discretion.